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

At the November 6, 2020 stakeholder session in this proceeding Commission Staff requested feedback regarding the following: (i) Staff's straw proposal and the additional presentations provided concerning compliance with Governor Whitmer's Executive Directive 2020-10; and (ii) the presentations given including those from the Electric Power Research Institute ("EPRI"), Duke Energy, and Dominion Energy regarding the integration and alignment of generation, transmission, and distribution planning. ABATE's general comments on these issues are included below.

II. COMMENTS

A. Generation retirements should be coordinated pursuant to a generation retirement analysis.

Executive Directive 2020-10 directs, among other things, that Michigan "will aim to achieve a 28% reduction below 2005 levels in greenhouse gas emissions by 2025."[1] Staff's straw proposals presented at this workgroup's October 21, 2020 session as well as the presentations

[1] https://www.michigan.gov/whitmer/0,9309,7-387-90499_90704-540278--,00.html

ClarkHill\07411\414800\261252670.v1-11/12/20 provided at the November 6, 2020 session included consideration of generation resource transitioning and, by extension, retirement of coal generation.

In considering such retirements it is important they are coordinated pursuant to a generation retirement analysis and "scorecard" review similar to what other utilities (such as the Northern Indiana Public Service Company ("NIPSCO")[2]) have utilized. Considering retirements based on such analyses will ensure decisions regarding what units need to be retired and when such retirements should occur are reasonable and informed. Such a process will also assist with transparency as well as customer expectations and foresight.

B. Transparency, stakeholder engagement, and probabilistic modeling are key elements of generation, distribution, and transmission system planning.

As ABATE has indicated throughout this proceeding (as well as the distribution system planning workgroup sessions conducted in Docket No. U-20147), it is imperative that planning processes involve transparency, stakeholder engagement and involvement to the greatest extent possible, and probabilistic modeling to properly identify and evaluate risk.

As such, Staff's questions for stakeholder discussion at the November 6, 2020 session regarding externalities are important. Coordinating review of generation, distribution, and transmission system planning through the IRP process and pursuant to the MIRPP Filing Requirements will ensure a reasonable and credible approach to these issues, including the consideration of externalities and the methods for addressing the same. Further, probabilistic modeling and risk assessment is important to appropriately gauge externalities and risks, particularly their likelihood and magnitude. In other words, when considering externalities and

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[2] See e.g. NIPSCO's 2018 Integrated Resource Plan at 145, 149-58. NIPSCO's retirement analysis was undertaken to "evaluate the preferred coal retirement strategy over time." https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2018-nipsco-irp.pdf?sfvrsn=15

risk it is necessary to determine the size of the risk being avoided when analyzing the cost of avoidance. This type of conscientious planning can help mitigate the potential for fears and concerns regarding reliability and resilience to result in investments beyond an amount and before a time when such measures may be necessary. In short, such modeling can help determine the risks various parties may be willing to accept or mitigate in alternative methods and can avoid unnecessary cost increases.

III. CONCLUSION

Pursuant to Staff's solicitation of feedback ABATE recommends Staff incorporate consideration of the issues and points raised above into this stakeholder proceeding.

Respectfully submitted,

CLARK HILL PLC

By: Stephen A. Campbell

Digitally signed by: Stephen A. Campbell
DN: CN = Stephen A. Campbell email = scampbell@clarkhill.com C = US O = Clark Hill PLC
Date: 2020.11.16 13:01:07 -05'00'

Stephen A. Campbell (P76684)
Attorneys for Association of Businesses Advocating Tariff Equity
212 East César E. Chávez Avenue
Lansing, Michigan 48903
517-318-3100
scampbell@clarkhill.com

Date: November 16, 2020

ACEEE COMMENTS ON THE NOVEMBER 6, 2020 PRESENTATIONS IN THE ADVANCED PLANNING PROCESS

by

Martin Kushler, Ph.D.

Senior Fellow, ACEEE

ACEEE appreciates the open public process that the MPSC is conducting in this matter, and the opportunity to comment at appropriate times in the process.

Regarding the presentations on November 6th, I just have one comment at this point. That is on the otherwise excellent presentation by Douglas Jester. On slide 31 of the meeting slide deck, there appears the following bullet:

- Efficiency measures such as shell improvements that reduce the need for heat will make electrification cheaper but need not be treated as a prerequisite of electrification.

I am concerned that this statement risks greatly under-valuing the importance of energy efficiency in making building electrification feasible. ACEEE supports beneficial electrification that reduces fossil energy use and greenhouse gas emissions. However, absent substantial building shell efficiency improvement, electrification will not only be overly expensive to the building owner (both in first cost and operational cost of the heat pump equipment and back-up heating sources), but also to the electric utility system which will require much more electric supply. The notion of requiring that buildings achieve some particular level of high efficiency before receiving subsidies to electrify should definitely not be rejected out of hand, and at a minimum, aggressive policies should be in place to incent deep building shell efficiency improvements as a part of any electrification program.

The Center for Energy and Environment (CEE) in Minnesota recently published an analysis of the effects of installing air source heat pumps (ASHP) vs. installing ASHP along with deep efficiency improvements in the building shell.
https://www.mncee.org/blog/october-2020/electrification,-energy-efficiency,-and-peak-deman/

They found that including the deep efficiency improvements not only greatly reduced customer costs, it also greatly reduced annual electricity use as well as both summer and winter peak demand…relative to the impacts of simply installing the ASHP.

More broadly, numerous top experts have highlighted the crucial role that energy efficiency must make in any decarbonization strategy. In the seminal report *Pathways to Deep Decarbonization* (cited below), they identify the "three pillars of energy system transformation" as (1) energy efficiency and conservation; (2) decarbonizing electricity and fuels; and (3) switching energy end-uses to lower-carbon, and eventually zero-carbon energy carriers. They also conclude the following, which has particular relevance for the issue of coupling energy efficiency with ASHP:

> "All pathways incorporate these three pillars in an interactive way. For example, energy efficiency and conservation (pillar 1) reduces potential electricity demand and therefore facilitates the decarbonization of electricity (pillar 2) by limiting the need for deployment of low-carbon generation." (p. 8)

Numerous other top experts have described the essential role that energy efficiency must play in any pathway to decarbonization. I provide four example sources below.

In conclusion, I hope that the MPSC Staff and the Commission will emphasize the essential role of energy efficiency in achieving the objectives laid out in Governor Whitmer's Executive Directive, including the importance of combining aggressive building shell efficiency improvements with any policy to advance building electrification.

Thank-you very much for your attention.

Sincerely,

Martin Kushler, Ph.D.
Senior Fellow
ACEEE

Sources for Deep Decarbonization Analyses

PATHWAYS TO DEEP DECARBONIZATION
Published by the Sustainable Development Solutions Network (SDSN) and the Institute for Sustainable Development and International Relations (IDDRI), December 2015
https://www.iddri.org/en/publications-and-events/report/pathways-deep-decarbonization-2015-synthesis-report

OPTIONALITY, FLEXIBILITY, & INNOVATION: PATHWAYS FOR DEEP DECARBONIZATION IN CALIFORNIA
Energy Futures Initiative, 2019
https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5cadebd04cd61c00017a563b/1554901977873/EFI+California+Summary+DE+PM.pdf

HALFWAY THERE: ENERGY EFFICIENCY CAN CUT ENERGY USE AND GREENHOUSE GAS EMISSIONS IN HALF BY 2050
ACEEE, September 2019
https://www.aceee.org/research-report/u1907

ELECTRIFICATION, ENERGY EFFICIENCY, AND PEAK DEMAND
MNCEE blog Posted by Jenny Edwards October 16, 2020
https://www.mncee.org/blog/october-2020/electrification,-energy-efficiency,-and-peak-deman/

Michigan Energy Innovation Business Council
115 W. Allegan, Suite 710
Lansing, MI 48933

Advanced Energy Economy
1010 Vermont Ave NW, Suite 1050
Washington, DC 20005

November 17, 2020

The Michigan Energy Innovation Business Council (Michigan EIBC) and Advanced Energy Economy (AEE) appreciate the opportunity to provide feedback in response to the Staff straw proposal and the alternative proposals presented at the November 6, 2020 Integration of Resource/Distribution/Transmission Planning Workgroup Meeting. We support the Commission's continued attention to these important issues, and view this open, transparent stakeholder collaboration as one of the most important tools for ensuring that planning processes succeed and are aligned with state policy. AEE and Michigan EIBC provide brief initial reactions to the proposals below. We look forward to providing detailed feedback on Staff's forthcoming recommendations to the Commission and to our continued involvement in this workgroup.

Respectfully Submitted,

/S/
Laura Sherman
President
Michigan EIBC
Lansing, MI
laura@mieibc.org
www.mieibc.org

/S/
Ryan Katofsky
Managing Director
Advanced Energy Economy
rkatofsky@aee.net
www.aee.net

Comments on straw proposals for modifying IRP planning parameters

For IRPs filed before 2023, Michigan EIBC and AEE prefer Option 2 in the Staff straw proposal (Slide 6). This option is consistent with the trajectory outlined in ED 2020-10. It ensures that utility reporting reflects the 2050 goals while also providing visibility into the near-term carbon reduction goals.

AEE and Michigan EIBC support the 5 Lakes Energy analysis and recommend that IRPs reflect its main conclusion that in the near-term, the electricity sector needs to "over-deliver" on GHG reductions to meet the statewide 2025 targets, since other sectors (buildings and transportation) are expected to decarbonize more slowly. 5 Lakes Energy estimated that a 36% reduction in the electricity sector would be required to meet a 28% economy-wide reduction. More generally, the power sector is the linchpin for broader economy-wide decarbonization, and ambitious near-term goals are therefore needed to facilitate decarbonization in other sectors. We encourage the Commission to build upon the 5 Lakes Energy analysis to determine the appropriate 2025 percentage reductions needed for the power sector. These values should then be used as baseline assumptions in the IRP scenario modeling as described below.

Regarding the four options presented by Staff on how to adjust the IRPs filed in 2023 or after (Slide 5), we start from the premise that utilities should be assuming success in achieving at least the greenhouse gas (GHG) reduction goals in ED 2020-10, adjusted as described above. We therefore support the inclusion of both the interim (2025) and long-term (2050) goals as baseline assumptions in all scenarios -- not only in BAU scenarios or as sensitivities. As currently defined, we do not think any of the four options proposed by Staff accomplish this, but Options 3 and 4 come closest. Option 4 has an eye towards 2050 compliance whereas Option 3 is focused on the 2025 goals. We recommend combining these two scenarios such that the detailed IRP modeling would show how interim targets will be met and how the utilities are on a clear trajectory to meeting the 2050 goals, even if the precise resource mix beyond the IRP planning horizon is not fully defined. However, both Options 3 and 4 treat the GHG reduction goals as a sensitivity. For the state to achieve these GHG reductions, they must be treated as baseline assumptions in all the scenarios and cannot be treated as sensitivities. This may necessitate further changes to the scenarios to ensure they are actually different and go beyond the baseline GHG reduction goals.

Additional considerations with respect to IRP planning

Economy-wide decarbonization requires increased building and transportation electrification. Utility planning and forecasting must therefore (i) reflect this expected increase in load and (ii) facilitate utilities playing an active role in decarbonizing the transportation and building sectors through increased electrification and energy efficiency. To adequately prepare for fundamental changes to the energy mix, and to ensure that sufficient clean resources are deployed, these parameters must be considered and reflected in the IRP analyses. It will also become increasingly important that utilities include load management opportunities in their IRP modeling to help manage the expected increased load from electrification. For example, there are significant opportunities for meeting increased total electricity demand without proportional increases in peak demand. The 5 Lakes Energy analysis provides useful information regarding the expected increase in electricity consumption as buildings and transportation electrify, and the Commission and utilities should build on it.

This fundamental change in how electricity will be used also highlights the timeliness and need for this workgroup, since meeting the GHG reduction goals require fundamental rethinking of how we manufacture energy technologies and how we generate, distribute and use electricity. If utilities can better integrate distribution planning with IRP planning, this will allow them to fully account for load changes, but also will enable utilities to leverage the significant investments that will be made by customers and providers of energy products and services. It is our firm view that this will result in more robust IRPs, lower costs for customers and a more reliable and resilient grid.

Comments of Armada Power to the Integration of Resource/Distribution/Transmission Planning Workgroup
November 17, 2020

Armada Power submits these comments in response to the presentations and staff straw proposal to include Executive Directive 2020-10 into the Integrated Resource Planning ("IRP") process.

Armada Power is a U.S. based company whose U.S. manufactured device adapts water heater load beyond traditional demand response for use by utilities as a grid asset for DER integration.

Armada's technology can help achieve the use of IRP as a path to zero emissions goals but at a lower cost than traditional battery investments..

In response to Executive Directive 2020-10 for Michigan to achieve carbon neutrality by 2050, the Michigan Public Service Commission Staff issued a straw proposal to incorporate ED 2020-10 into the Integrated Resource Planning process. Traditional Integrated Resource Plans have focused on generation sources and grid improvements at the wires level (circuits, distribution, transmission, etc). In order to balance the costs of traditional carbon reduction methods such as expanded DER interconnection and ultimately achieve a zero carbon goal, the IRP process must also look at alternatives to expensive distribution system upgrades. While the Staff proposal includes expanded DER and other technologies - as pointed out by other parties - a carbon neutral IRP must include options beyond the traditional wires and generation source focus.

As pointed out by Duke and Dominion, the need for a flexible system that meets the needs of customers while allowing for the dynamic load resulting from renewables is a core function of today's utilities. To achieve these new functions utility IRP's must incorporate a non-traditional view.

The Armada technology is an integrated meter and voltage measurement device that also provides down-to-the-second readings and control of any electric water heater. Armada's controller retrofits directly to standard residential electric water heaters offering the ability to control and hold water heater load on a fleet basis for demand response, voltage variation controls and, at the customer level, energy efficiency. The integrated metering functions allow a utility to use water heater load as a battery service to the grid that does not degrade at a faster rate with usage. For example a water heater using Armada can be dispatched hourly, daily, monthly. But, unlike a battery, the frequency of use does not degrade the device or the water heater.

Most existing water heater controllers utilize one-way communication. So the utility would need to measure some kind of renewable generation imbalance and then dispatch the entire fleet with a one-way signal rather than a specific portion of the grid. This would be a problem if, for example, one circuit had a cloud over it and another adjacent circuit did not - the one size fits the whole could result in over correction causing other issues. Armada allows for a circuit specific solution. Our technology has the ability to locally sense voltage and frequency deviation, so we could react on a local circuit condition automatically. Or have individual zones controlled at the utility level. Many traditional water heater controllers are just simple timers, which obviously would not help in a dynamic situation where renewable generation suddenly increased or decreased. Armada uses smart algorithms that dampen oscillation issues. A "dumb" switch might just turn on and off according to a simple set point, which could cause the grid to oscillate. We have a patent on simulated droop control and the system is continuously re-optimized so that large voltage and frequency deviations receive a faster response while smaller deviations receive a slower response.

Ultimately, an IRP including fleet use of Armada unlike traditional water heater direct load control would allow a utility to value stack demand response, capacity value, voltage response with customer time-of-use and energy efficiency measures.

Finally, our two-way communication and revenue grade metering provide accurate measurement and verification so grid operators can see the contribution of our distributed storage and can use the data for future planning and analysis.

Why is Armada a value-add to an IRP carbon reduction goal in combination with EV and battery storage?

Armada achieves a per-device net reduction of 1 to 6 tons of carbon per year when used to firm the delivery of renewable energy sources. However, it also extends the use of other carbon reducing technologies such as batteries.

Our energy storage capability offers supplemental services which work as an additional resource to batteries for significantly less cost. For most applications, water heater control is five times more cost effective than electrochemical batteries for grid applications. Armada responds just as fast as a battery without any wear or danger of fire and explosion.

Batteries have opportunity costs for charging to grid calls rather than what would be optimal for the battery chemistry. The addition of technology which can reduce the number of grid calls upon a battery will extend the life of the battery while maintaining grid functionality.

Because nearly every customer requires at least one water heater regardless of its potential as a grid asset, Armada's technology can be installed in many more locations for the same initial cost as a single battery in a single location. A utility could use the existing electric water heaters of its customers at a cost of $135 - $150 per device versus multiple batteries. Additionally, batteries have round trip losses which degrade the battery based on use, limiting their lifespan.

Armada's technology increases the lifespan of more expensive batteries by reducing the number of discharge and recharge cycles on them. This combination of cost-effective bulk deployment and reduced lifespan-reducing strain on batteries will allow the IRP budget to stretch further while allowing for battery investment in the most critical areas of the grid.

What value can a water heater as a grid resource provide for voltage regulation?

For existing Volt/VAR, Armada would be complementary. Utilities in a designed grid will need to reduce voltage in certain situations down to minimum without dropping a customer too low. The design of Armada allows for a faster way to get voltage readings from every end point/premise on the circuit where an electric water heater exists. The device has the ability to provide a real-time (down to 1 second intervals) voltage read. We currently redispatch every 2 seconds for PJM Frequency regulation. This provides the utility with another level of insight into areas of their grid that traditional water heater demand response programs and technologies do not.

In addition, Armada has the capability to expand usage and control returns after an outage. For example, if Armada had a solar output signal from the utility we could ramp up and use the excess power on specific grid points without the need for additional circuits. We do this by holding our water heaters at 50% capacity which provide for a 50% band to increase power for consumption. While all of this would be blind to the customer who maintains full hot water access, it provides the utility with another tool for grid control. This type of control also allows for Armada to control the ramp up of water heater usage after an outage. We can bring customers to a specific level of comfortable hot water without fully increasing the usage allowing for a smoother transition to full power.

What value in addition to carbon reduction could the individual residential customer achieve by combining water heater controls like Armada in an IRP?

Attached to these comments is an initial analysis[1] of the DTE time-of-use tariff options for a residential customer which shows that adding Armada to those products could provide between \$25-\$55 a year in estimated additional savings. If DTE changed its existing water heater program to also include a designed time-of-use option, the savings would increase to a potential of \$84 - \$142 annually.

It has been noted by all parties in the IRP working group that it will require a mix of grid investment, electrification and energy efficiency to meet the carbon goals. The use of water heaters as a resource in addition to electrification for carbon reduction is another aspect of IRP that should be required. However, how to balance the costs of beneficial electrification for ratepayers and customers becomes a critical question.

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[1] Analysis is based on a basic non-weather adjusted calculation which assumes a flat 30 days monthly billing cycle and a flat 8 kWh/day usage. The High Impact option is not a likely scenario for comfort but is included for illustrative purposes.

Electrification of water heating as noted by 5Lakes is another piece of the total puzzle to achieve zero carbon. However, it does not nor should it require purchasing and replacing all customers' water heaters. A simple bolt-on to existing electric water heaters can be achieved now. In addition, future replacements should not force customers or ratepayers to invest in fully smart or heat pump type water heaters to achieve the carbon goal when less expensive but similar solutions exist. Armada simply installs onto a standard water heater and can achieve the same goals as a smart/heat pump water heater and allow the "dumb" water heater to act as a grid asset for a fraction of the price. Using Armada in combination with an IRP for carbon reduction, would allow for replacement of gas water heaters with standard electric water heaters for less than half the cost of a smart or heat pump style.

Summary:

Traditionally, water heaters have been viewed as a limited source of demand response or an energy efficient appliance. However, new technologies allow for the water heater on a fleet basis to function as a true grid resource. Aggressive carbon goals will take investments that should look beyond traditional DER+Battery options. Battery functionality for water heaters will allow a utility to add an additional and more economic option to their grid planning review and address constraints on their system in non-traditional ways while also providing residential customers with cost reductions.

Thank you for the opportunity to comment. For additional information or questions please contact:

Teresa Ringenbach
Armada Power, LLC
V.P., Government Affairs and Business Development
Mobile: (216) 308-0556
Email: tringenbach@nationwideenergypartners.com

DTE Time of Day Rate Savings through Armada Power Optimization - Water Heaters Only
No Comfort Impact

	Total Daily Avg kWh	8											
	HE	Wkday Avg % Uncontrolled	Wkday Avg kWh	Summer-energy	Summer-energy-	Winter-energy	Winter-energy-	TOU Controlled	TOU Controlled	Summer-energy-	Winter-energy-	energy delta	energy delta
0:00	1	2%	0.16	$0.1203	$0.02	$0.1182	$0.02	2%	2%	$0.0193	$0.02		
1:00	2	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
2:00	3	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
3:00	4	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
4:00	5	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
5:00	6	2%	0.16	$0.1203	$0.02	$0.1182	$0.02	2%	2%	$0.0193	$0.02		
6:00	7	5%	0.4	$0.1203	$0.05	$0.1182	$0.05	5%	5%	$0.0481	$0.05		
7:00	8	7%	0.56	$0.1203	$0.07	$0.1182	$0.07	7%	7%	$0.0674	$0.07		
8:00	9	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	6%	6%	$0.0578	$0.06		
9:00	10	5%	0.4	$0.1203	$0.05	$0.1182	$0.05	5%	5%	$0.0481	$0.05		
10:00	11	4%	0.32	$0.1203	$0.04	$0.1182	$0.04	6%	6%	$0.0578	$0.06		
11:00	12	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	1%	1%	$0.0182	$0.02	0.16	0.16
12:00	13	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	1%	1%	$0.0182	$0.02	0.16	0.16
13:00	14	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	1%	1%	$0.0182	$0.02	0.16	0.16
14:00	15	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	2%	2%	$0.0363	$0.03	0.08	0.08
15:00	16	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	2%	2%	$0.0363	$0.03	0.08	0.08
16:00	17	4%	0.32	$0.2271	$0.07	$0.2021	$0.06	3%	3%	$0.0545	$0.05	0.08	0.08
17:00	18	5%	0.4	$0.2271	$0.09	$0.2021	$0.08	3%	3%	$0.0545	$0.05	0.16	0.16
18:00	19	5%	0.4	$0.2271	$0.09	$0.2021	$0.08	3%	3%	$0.0545	$0.05	0.16	0.16
19:00	20	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	12%	12%	$0.1155	$0.11		
20:00	21	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	13%	13%	$0.1251	$0.12		
21:00	22	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	8%	8%	$0.0770	$0.08		
22:00	23	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	8%	8%	$0.0770	$0.08		
23:00	24	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	6%	6%	$0.0578	$0.06		
		100%			**$1.21**		**$1.14**	100%	100%	**$1.10**	**$1.05**	1.04	1.04
				Summer Demand		Winter Demand				Summer Demand	Winter Demand		
		peak demand	0.64	$0.00	**$0.00**	$0.00	**$0.00**	3%	3%	**$0.00**	**$0.00**		

Monthly Analysis			Uncontrolled	Uncontrolled	TOU Summer	TOU Winter
# of weekdays in month		22	$26.63	$25.09	$24.18	$23.17
# of weekend in month		8	$7.70	$7.56	$7.70	$7.56
	Demand Cost		$0.00	$0.00	$0.00	$0.00
	Totals		**$34.33**	**$32.65**	**$31.88**	**$30.73**
Summer Cost Differential Control vs			$2.44			
Winter Cost Differential Control vs			$1.92			
# of Summer Months		5	$12.22			
# of Winter Months		7	$13.44			
	Annual Savings Total		**$25.66**			

	Summer	**Winter**
Months	June 1 - Oct 31	Nov 1 - May 31
On-Peak Time	11 am - 7 pm	11 am - 7 pm
On-Peak Rate	$ 0.2271	$ 0.2021
Off-Peak Rate	$ 0.1203	$ 0.1182

DTE Time of Day Rate Savings through Armada Power Optimization - Water Heaters Only
Low Comfort Impact

	Total Daily Avg kWh	8											
	HE	Wkday Avg % Uncontrolled	Wkday Avg kWh	Summer-energy	Summer-energy-	Winter-energy	Winter-energy-	TOU Controlled	TOU Controlled	Summer-energy-	Winter-energy-	energy delta	energy delta
0:00	1	2%	0.16	$0.1203	$0.02	$0.1182	$0.02	2%	2%	$0.0193	$0.02		
1:00	2	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
2:00	3	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
3:00	4	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
4:00	5	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
5:00	6	2%	0.16	$0.1203	$0.02	$0.1182	$0.02	2%	2%	$0.0193	$0.02		
6:00	7	5%	0.4	$0.1203	$0.05	$0.1182	$0.05	5%	5%	$0.0481	$0.05		
7:00	8	7%	0.56	$0.1203	$0.07	$0.1182	$0.07	7%	7%	$0.0674	$0.07		
8:00	9	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	6%	6%	$0.0578	$0.06		
9:00	10	5%	0.4	$0.1203	$0.05	$0.1182	$0.05	5%	5%	$0.0481	$0.05		
10:00	11	4%	0.32	$0.1203	$0.04	$0.1182	$0.04	6%	6%	$0.0578	$0.06		
11:00	12	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	1%	1%	$0.0182	$0.02	0.16	0.16
12:00	13	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	1%	1%	$0.0182	$0.02	0.16	0.16
13:00	14	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	1%	1%	$0.0182	$0.02	0.16	0.16
14:00	15	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	1%	1%	$0.0182	$0.02	0.16	0.16
15:00	16	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	1%	1%	$0.0182	$0.02	0.16	0.16
16:00	17	4%	0.32	$0.2271	$0.07	$0.2021	$0.06	1%	1%	$0.0182	$0.02	0.24	0.24
17:00	18	5%	0.4	$0.2271	$0.09	$0.2021	$0.08	2%	2%	$0.0363	$0.03	0.24	0.24
18:00	19	5%	0.4	$0.2271	$0.09	$0.2021	$0.08	2%	2%	$0.0363	$0.03	0.24	0.24
19:00	20	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	15%	15%	$0.1444	$0.14		
20:00	21	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	16%	16%	$0.1540	$0.15		
21:00	22	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	8%	8%	$0.0770	$0.08		
22:00	23	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	8%	8%	$0.0770	$0.08		
23:00	24	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	6%	6%	$0.0578	$0.06		
		100%			**$1.21**		**$1.14**	100%	100%	**$1.05**	**$1.01**	1.52	1.52
				Summer Demand		Winter Demand				Summer Demand	Winter Demand		
		peak demand	0.64	$0.00	**$0.00**	$0.00	**$0.00**	2%	2%	**$0.00**	**$0.00**		

Monthly Analysis			Uncontrolled	Uncontrolled	TOU Summer	TOU Winter
# of weekdays in month		22	$26.63	$25.09	$23.06	$22.28
# of weekend in month		8	$7.70	$7.56	$7.70	$7.56
	Demand Cost		$0.00	$0.00	$0.00	$0.00
	Totals		**$34.33**	**$32.65**	**$30.76**	**$29.85**

Summer Cost Differential Control vs			$3.57
Winter Cost Differential Control vs			$2.81
# of Summer Months		5	$17.86
# of Winter Months		7	$19.65
	Annual Savings Total		**$37.50**

	Summer	**Winter**
Months	June 1 - Oct 31	Nov 1 - May 31
On-Peak Time	11 am - 7 pm	11 am - 7 pm
On-Peak Rate	$ 0.2271	$ 0.2021
Off-Peak Rate	$ 0.1203	$ 0.1182

DTE Time of Day Rate Savings through Armada Power Optimization - Water Heaters Only

Maximum Savings

Total Daily Avg kWh		8											
HE		Wkday Avg % Uncontrolled	Wkday Avg kWh	Summer-energy	Summer-energy-	Winter-energy	Winter-energy-	TOU Controlled	TOU Controlled	Summer-energy-	Winter-energy-	energy delta	energy delta
0:00	1	2%	0.16	$0.1203	$0.02	$0.1182	$0.02	2%	2%	$0.0193	$0.02		
1:00	2	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
2:00	3	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
3:00	4	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
4:00	5	1%	0.08	$0.1203	$0.01	$0.1182	$0.01	1%	1%	$0.0096	$0.01		
5:00	6	2%	0.16	$0.1203	$0.02	$0.1182	$0.02	2%	2%	$0.0193	$0.02		
6:00	7	5%	0.4	$0.1203	$0.05	$0.1182	$0.05	5%	5%	$0.0481	$0.05		
7:00	8	7%	0.56	$0.1203	$0.07	$0.1182	$0.07	7%	7%	$0.0674	$0.07		
8:00	9	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	6%	6%	$0.0578	$0.06		
9:00	10	5%	0.4	$0.1203	$0.05	$0.1182	$0.05	5%	5%	$0.0481	$0.05		
10:00	11	4%	0.32	$0.1203	$0.04	$0.1182	$0.04	6%	6%	$0.0578	$0.06		
11:00	12	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	0%	0%	$0.0000	$0.00	0.24	0.24
12:00	13	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	0%	0%	$0.0000	$0.00	0.24	0.24
13:00	14	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	0%	0%	$0.0000	$0.00	0.24	0.24
14:00	15	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	0%	0%	$0.0000	$0.00	0.24	0.24
15:00	16	3%	0.24	$0.2271	$0.05	$0.2021	$0.05	0%	0%	$0.0000	$0.00	0.24	0.24
16:00	17	4%	0.32	$0.2271	$0.07	$0.2021	$0.06	0%	0%	$0.0000	$0.00	0.32	0.32
17:00	18	5%	0.4	$0.2271	$0.09	$0.2021	$0.08	0%	0%	$0.0000	$0.00	0.4	0.4
18:00	19	5%	0.4	$0.2271	$0.09	$0.2021	$0.08	0%	0%	$0.0000	$0.00	0.4	0.4
19:00	20	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	20%	20%	$0.1925	$0.19		
20:00	21	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	21%	21%	$0.2021	$0.20		
21:00	22	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	8%	8%	$0.0770	$0.08		
22:00	23	8%	0.64	$0.1203	$0.08	$0.1182	$0.08	8%	8%	$0.0770	$0.08		
23:00	24	6%	0.48	$0.1203	$0.06	$0.1182	$0.06	6%	6%	$0.0578	$0.06		
		100%			**$1.21**		**$1.14**	100%	100%	**$0.96**	**$0.95**	2.32	2.32
				Summer Demand		Winter Demand				Summer Demand	Winter Demand		
		peak demand	0.64	$0.00	**$0.00**	$0.00	**$0.00**	0%	0%	**$0.00**	**$0.00**		

Monthly Analysis			Uncontrolled	Uncontrolled	TOU Summer	TOU Winter
# of weekdays in month		22	$26.63	$25.09	$21.18	$20.80
# of weekend in month		8	$7.70	$7.56	$7.70	$7.56
	Demand Cost		$0.00	$0.00	$0.00	$0.00
	Totals		**$34.33**	**$32.65**	**$28.88**	**$28.37**

Summer Cost Differential Control vs			$5.45
Winter Cost Differential Control vs			$4.28
# of Summer Months		5	$27.26
# of Winter Months		7	$29.99
	Annual Savings Total		**$57.24**

	Summer	**Winter**
Months	June 1 - Oct 31	Nov 1 - May 31
On-Peak Time	11 am - 7 pm	11 am - 7 pm
On-Peak Rate	$ 0.2271	$ 0.2021
Off-Peak Rate	$ 0.1203	$ 0.1182

DTE Dynamic Peak Pricing Rate Savings through Armada Power Optimization - Water Heaters Only
No Comfort Impact

Total Daily Avg kWh		8											
HE		Wkday Avg % Uncontrolled	Wkday Avg kWh	Summer-energy	Summer-energy-	Winter-energy	Winter-energy-	TOU Controlled	TOU Controlled	Summer-energy-	Winter-energy-	energy delta	energy delta
0:00	1	2%	0.16	$0.1141	$0.02	$0.1141	$0.02	8%	8%	$0.0730	$0.07		
1:00	2	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
2:00	3	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
3:00	4	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
4:00	5	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
5:00	6	2%	0.16	$0.1141	$0.02	$0.1141	$0.02	2%	2%	$0.0182	$0.02		
6:00	7	5%	0.4	$0.1141	$0.05	$0.1141	$0.05	6%	6%	$0.0547	$0.05		
7:00	8	7%	0.56	$0.1583	$0.09	$0.1583	$0.09	7%	7%	$0.0887	$0.09	0	0
8:00	9	6%	0.48	$0.1583	$0.08	$0.1583	$0.08	6%	6%	$0.0760	$0.08	0	0
9:00	10	5%	0.4	$0.1583	$0.06	$0.1583	$0.06	5%	5%	$0.0633	$0.06	0	0
10:00	11	4%	0.32	$0.1583	$0.05	$0.1583	$0.05	4%	4%	$0.0507	$0.05	0	0
11:00	12	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	3%	3%	$0.0380	$0.04	0	0
12:00	13	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	3%	3%	$0.0380	$0.04	0	0
13:00	14	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	3%	3%	$0.0380	$0.04	0	0
14:00	15	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	3%	3%	$0.0380	$0.04	0	0
15:00	16	3%	0.24	$0.2321	$0.06	$0.2321	$0.06	1%	1%	$0.0186	$0.02	0.16	0.16
16:00	17	4%	0.32	$0.2321	$0.07	$0.2321	$0.07	1%	1%	$0.0186	$0.02	0.24	0.24
17:00	18	5%	0.4	$0.2321	$0.09	$0.2321	$0.09	1%	1%	$0.0186	$0.02	0.32	0.32
18:00	19	5%	0.4	$0.2321	$0.09	$0.2321	$0.09	1%	1%	$0.0186	$0.02	0.32	0.32
19:00	20	6%	0.48	$0.1583	$0.08	$0.1583	$0.08	6%	6%	$0.0760	$0.08	0	0
20:00	21	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	8%	8%	$0.1013	$0.10	0	0
21:00	22	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	8%	8%	$0.1013	$0.10	0	0
22:00	23	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	8%	8%	$0.1013	$0.10	0	0
23:00	24	6%	0.48	$0.1141	$0.05	$0.1141	$0.05	12%	12%	$0.1095	$0.11		
		100%			**$1.30**		**$1.30**	100%	100%	**$1.18**	**$1.18**	1.04	1.04
				Summer Demand		Winter Demand				Summer Demand	Winter Demand		
		peak demand	0.64	$0.00	**$0.00**	$0.00	**$0.00**	3%	3%	**$0.00**	**$0.00**		

Monthly Analysis			Uncontrolled	Uncontrolled	TOU Summer	TOU Winter
# of weekdays in month		22	$28.59	$28.59	$25.89	$25.89
# of weekend in month		8	$7.30	$7.30	$7.30	$7.30
	Demand Cost		$0.00	$0.00	$0.00	$0.00
	Totals		**$35.89**	**$35.89**	**$33.19**	**$33.19**

Summer Cost Differential Control vs			$2.70
Winter Cost Differential Control vs			$2.70
# of Summer Months		5	$13.51
# of Winter Months		7	$18.91
	Annual Savings Total		**$32.42**

DTE Dynamic Peak Pricing Rate Savings through Armada Power Optimization - Water Heaters Only

Low Comfort Impact

Total Daily Avg kWh		8											
HE		Wkday Avg % Uncontrolled	Wkday Avg kWh	Summer-energy	Summer-energy-	Winter-energy	Winter-energy-	TOU Controlled	TOU Controlled	Summer-energy-	Winter-energy-	energy delta	energy delta
0:00	1	2%	0.16	$0.1141	$0.02	$0.1141	$0.02	12%	12%	$0.1095	$0.11		
1:00	2	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
2:00	3	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
3:00	4	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
4:00	5	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
5:00	6	2%	0.16	$0.1141	$0.02	$0.1141	$0.02	2%	2%	$0.0182	$0.02		
6:00	7	5%	0.4	$0.1141	$0.05	$0.1141	$0.05	6%	6%	$0.0547	$0.05		
7:00	8	7%	0.56	$0.1583	$0.09	$0.1583	$0.09	7%	7%	$0.0887	$0.09	0	0
8:00	9	6%	0.48	$0.1583	$0.08	$0.1583	$0.08	6%	6%	$0.0760	$0.08	0	0
9:00	10	5%	0.4	$0.1583	$0.06	$0.1583	$0.06	5%	5%	$0.0633	$0.06	0	0
10:00	11	4%	0.32	$0.1583	$0.05	$0.1583	$0.05	4%	4%	$0.0507	$0.05	0	0
11:00	12	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	3%	3%	$0.0380	$0.04	0	0
12:00	13	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	3%	3%	$0.0380	$0.04	0	0
13:00	14	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	2%	2%	$0.0253	$0.03	0.08	0.08
14:00	15	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	2%	2%	$0.0253	$0.03	0.08	0.08
15:00	16	3%	0.24	$0.2321	$0.06	$0.2321	$0.06	0%	0%	$0.0000	$0.00	0.24	0.24
16:00	17	4%	0.32	$0.2321	$0.07	$0.2321	$0.07	0%	0%	$0.0000	$0.00	0.32	0.32
17:00	18	5%	0.4	$0.2321	$0.09	$0.2321	$0.09	0%	0%	$0.0000	$0.00	0.4	0.4
18:00	19	5%	0.4	$0.2321	$0.09	$0.2321	$0.09	0%	0%	$0.0000	$0.00	0.4	0.4
19:00	20	6%	0.48	$0.1583	$0.08	$0.1583	$0.08	6%	6%	$0.0760	$0.08	0	0
20:00	21	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	8%	8%	$0.1013	$0.10	0	0
21:00	22	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	8%	8%	$0.1013	$0.10	0	0
22:00	23	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	8%	8%	$0.1013	$0.10	0	0
23:00	24	6%	0.48	$0.1141	$0.05	$0.1141	$0.05	14%	14%	$0.1277	$0.13		
		100%			**$1.30**		**$1.30**	100%	100%	**$1.13**	**$1.13**	1.52	1.52
				Summer Demand		Winter Demand				Summer Demand	Winter Demand		
		peak demand	0.64	$0.00	**$0.00**	$0.00	**$0.00**	3%	3%	**$0.00**	**$0.00**		

Monthly Analysis			Uncontrolled	Uncontrolled	TOU Summer	TOU Winter
# of weekdays in month		22	$28.59	$28.59	$24.90	$24.90
# of weekend in month		8	$7.30	$7.30	$7.30	$7.30
	Demand Cost		$0.00	$0.00	$0.00	$0.00
	Totals		**$35.89**	**$35.89**	**$32.20**	**$32.20**

Summer Cost Differential Control vs			$3.69
Winter Cost Differential Control vs			$3.69
# of Summer Months		5	$18.44
# of Winter Months		7	$25.82
	Annual Savings Total		**$44.26**

DTE Dynamic Peak Pricing Rate Savings through Armada Power Optimization - Water Heaters Only
High Comfort Impact

Total Daily Avg kWh		8											
HE		Wkday Avg % Uncontrolled	Wkday Avg kWh	Summer-energy	Summer-energy-	Winter-energy	Winter-energy-	TOU Controlled	TOU Controlled	Summer-energy-	Winter-energy-	energy delta	energy delta
0:00	1	2%	0.16	$0.1141	$0.02	$0.1141	$0.02	17%	17%	$0.1551	$0.16		
1:00	2	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
2:00	3	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
3:00	4	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
4:00	5	1%	0.08	$0.1141	$0.01	$0.1141	$0.01	1%	1%	$0.0091	$0.01		
5:00	6	2%	0.16	$0.1141	$0.02	$0.1141	$0.02	2%	2%	$0.0182	$0.02		
6:00	7	5%	0.4	$0.1141	$0.05	$0.1141	$0.05	7%	7%	$0.0639	$0.06		
7:00	8	7%	0.56	$0.1583	$0.09	$0.1583	$0.09	6%	6%	$0.0760	$0.08	0.08	0.08
8:00	9	6%	0.48	$0.1583	$0.08	$0.1583	$0.08	5%	5%	$0.0633	$0.06	0.08	0.08
9:00	10	5%	0.4	$0.1583	$0.06	$0.1583	$0.06	4%	4%	$0.0507	$0.05	0.08	0.08
10:00	11	4%	0.32	$0.1583	$0.05	$0.1583	$0.05	3%	3%	$0.0380	$0.04	0.08	0.08
11:00	12	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	2%	2%	$0.0253	$0.03	0.08	0.08
12:00	13	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	2%	2%	$0.0253	$0.03	0.08	0.08
13:00	14	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	1%	1%	$0.0127	$0.01	0.16	0.16
14:00	15	3%	0.24	$0.1583	$0.04	$0.1583	$0.04	1%	1%	$0.0127	$0.01	0.16	0.16
15:00	16	3%	0.24	$0.2321	$0.06	$0.2321	$0.06	0%	0%	$0.0000	$0.00	0.24	0.24
16:00	17	4%	0.32	$0.2321	$0.07	$0.2321	$0.07	0%	0%	$0.0000	$0.00	0.32	0.32
17:00	18	5%	0.4	$0.2321	$0.09	$0.2321	$0.09	0%	0%	$0.0000	$0.00	0.4	0.4
18:00	19	5%	0.4	$0.2321	$0.09	$0.2321	$0.09	0%	0%	$0.0000	$0.00	0.4	0.4
19:00	20	6%	0.48	$0.1583	$0.08	$0.1583	$0.08	5%	5%	$0.0633	$0.06	0.08	0.08
20:00	21	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	7%	7%	$0.0887	$0.09	0.08	0.08
21:00	22	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	7%	7%	$0.0887	$0.09	0.08	0.08
22:00	23	8%	0.64	$0.1583	$0.10	$0.1583	$0.10	7%	7%	$0.0887	$0.09	0.08	0.08
23:00	24	6%	0.48	$0.1141	$0.05	$0.1141	$0.05	20%	20%	$0.1825	$0.18		
		100%			**$1.30**		**$1.30**	100%	100%	**$1.09**	**$1.09**	2.48	2.48
				Summer Demand		Winter Demand				Summer Demand	Winter Demand		
		peak demand	0.64	$0.00	**$0.00**	$0.00	**$0.00**	2%	2%	**$0.00**	**$0.00**		

Monthly Analysis			Uncontrolled	Uncontrolled	TOU Summer	TOU Winter
# of weekdays in month		22	$28.59	$28.59	$23.97	$23.97
# of weekend in month		8	$7.30	$7.30	$7.30	$7.30
	Demand Cost		$0.00	$0.00	$0.00	$0.00
	Totals		**$35.89**	**$35.89**	**$31.27**	**$31.27**

Summer Cost Differential Control vs		$4.62
Winter Cost Differential Control vs		$4.62
# of Summer Months	5	$23.12
# of Winter Months	7	$32.36
	Annual Savings Total	**$55.48**

DTE Residential Electric Service Rate vs. Water Heating Service Rate

Daily Energy Use	8
Residential Rate < 17kWh/day	0.15287
Residential Rate > 17kWh/day	0.17271
Water Heating Rate	0.11604
Water Heating Service Charge	1.95
RR Annual Cost < 17kWh	$446.38
RR Annual Cost > 17kWh	$504.31
WH Rate Annual Cost	$338.84
WH Service Charge	$23.40
Annual Savings Min	**$84.14**
Annual Savings Max	**$142.08**

DTE Electric Comments on Proposed Emissions Reporting Options

MI Power Grid– Advanced Planning Phase II

November 17, 2020

Staff's Straw Proposal presented in the October 21 collaborative meeting:

Emissions Reporting Options for IRPs filed in 2023 or After

Four options considered in the Straw Proposal to meet ED 2020-10 for utilities filing IRPs in 2023 or after

<table>
<tr><th>Option 1</th><th>Option 2</th><th>Option 3</th><th>Option 4</th></tr>
<tr><td colspan="2">Requires MIRPP <u>BAU</u> scenario change to include carbon goal of 28% reduction by 2025 as a sensitivity.</td><td>Requires MIRPP change to <u>all</u> scenarios reflecting the Carbon goal of 28% reduction by 2025 as a sensitivity.</td><td>Requires MIRPP change to all scenarios reflecting Carbon Neutrality by 2050 and therefore modeling as a sensitivity.</td></tr>
<tr><td colspan="3">If the utility preferred plan does not comply with the 2025 goal, include an optimized alternative plan that does comply with the 2025 goal and compare to the preferred plan.</td><td>If the utility preferred plan does not comply with the 2050 goal, include an optimized alternative plan that does comply with the 2050 goal and compare to the preferred plan.</td></tr>
<tr><td>Charts Carbon out to 2025</td><td colspan="2">Charts Carbon out to the 15-year planning horizon to illustrate a path toward 2050.</td><td>Charts Carbon out to 2050 in Exhibit to illustrate goal.</td></tr>
<tr><td colspan="3">Spreadsheet of CO2, SOx, Mercury, and PPM for each year of the 15-year planning horizon for the utility's preferred plan and each MIRPP scenario optimized plan.</td><td>Spreadsheet of CO2, SOx, Mercury, and PPM for each year out to 2050 for the utility's preferred plan and each MIRPP scenario optimized plan.</td></tr>
</table>

Emissions Reporting Options for IRPs filed before 2023

Two options considered in the Straw Proposal to meet ED 2020-10 for utilities filing an IRP before 2023

Option 1	Option 2
No MIRPP Update but Commission order directing addendum to filing requirements.	
Charts Carbon out to 2025 compared to 28% Carbon reduction.	Charts Carbon out to the 15-year planning horizon to illustrate a path toward 2050 and highlighting when the utility achieves a 28% reduction.
Spreadsheet of CO2, SOx, Mercury, and PPM for each year of the 15-year planning horizon for the utility's preferred plan and each MIRPP scenario optimized plan.	

Options presented by Joint Commenters[1] (D. Jester):

Joint Commenter Recommendations:

- Realistically meeting 28% economy-wide carbon emissions reduction from 2005 by 2025 requires power generation to achieve about a 36% carbon emissions reduction from 2018 by 2025.
- Achieving economy-wide power sector and nearly complete electrification of both transportation and buildings and substantial electrification of industrial heat. Electrification by 2050 requires all-electric equipment sales by about 2035, ramping up to that from 2020.
- MPSC IRP scenarios should incorporate these assumptions about power generation and load growth.

Options presented by I&M (Andrew Williamson):

Indiana Michigan Power Recommendations:

- Maintain single IRP for multi-state companies
- Clarify application of ED2020-10 to the IRP process
- Recognize need for future dispatchable generation

[1] Environmental Law and Policy Center, National Resources Defense Council, Vote Solar, Union of Concerned Scientists, Ecology Center, Michigan Environmental Council

Overall Comments:

DTE Electric (DTE or Company) appreciates the effort of Michigan Public Service Commission (MPSC), MPSC Staff (Staff) and all parties involved in this Integrated Planning collaborative. DTE will address each of the proposals from the stakeholders below.

Staff Proposal:

DTE is amenable to options 1 and 2 proposed by the MPSC Staff for IRP filings either before or after 2023. It should be noted that the Company expects to meet or exceed the 28% reduction of CO_2 by 2025 in its current plan and in future IRPs based on a baseline of 2005. In its 2019 Integrated Resource Plan, DTE communicated its carbon emissions reduction targets and provided details on how the Company plans to meet those targets. DTE is open to Option 3 based on the current MIRPP scenarios as detailed in MPSC Case No. U-18418. At this time, it is unclear what or how many scenarios will be required for IRPs filed in 2023 or after, therefore DTE requests clarification of the definition of all scenarios.

DTE does not agree with Option 4. As noted in MCL 460.6t, Section 3, utilities are required to file an integrated resource plan that provides a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations, to meet the utility's requirements to provide generation reliability, including meeting planning reserve margin and local clearing requirements determined by the commission or the appropriate independent system operator, and to meet all applicable state and federal reliability and environmental regulations over the ensuing term of the plan. Option 4 exceeds the time frames set forth in MCL 460.6t.

Joint Commenters Proposal:

DTE does not support requiring utilities to model other sectors in Michigan, besides its own generation plan. As noted above, an IRP is a plan to meet the utility’s load obligations and provide generation reliability. This proposal is outside the intent of an IRP.

Indiana Michigan Proposal:

DTE agrees that dispatchable generation will remain very important into the future.

Ms. Danielle Rogers
Ms. Naomi Simpson
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48917

November 17, 2020

Re: MPSC Staff Request for Feedback on Staff Straw Proposal and Alternative Proposals Addressing ED 2020-10

Ms. Rogers, Ms. Simpson,

On November 6, 2020, the Integration of Resource/Distribution/Transmission Planning workgroup held its third stakeholder session. At the conclusion of that session, the Staff of the Michigan Public Service Commission requested feedback on Staff's straw proposal and alternative proposals addressing ED 2020-10.

The Environmental Law & Policy Center, the Natural Resources Defense Council, Vote Solar, the Union of Concerned Scientists, the Ecology Center, Sierra Club, and the Michigan Environmental Council (Joint Commenters) respond to Staff's request for feedback below, and in the attached proposed edits to Section VIII of the Michigan Integrated Resource Planning Parameters.

1. **IRP scenarios should reflect the economy-wide nature of the Executive Directive and should extend the planning horizon to 2050.**

Executive Directive 2020-10 provides that "Michigan will aim to achieve economy-wide carbon neutrality no later than 2050." In addition, "the state will aim to achieve a 28% reduction below 2005 levels in greenhouse gas emissions by 2025."[1]

Douglas Jester's presentation[2] to the workgroup on Nov. 6 provided some initial level-setting data points to consider. In 2018, approximately 81% of greenhouse gas emissions were carbon dioxide, while methane made up 10%, nitrous oxide 7%, and fluorinated gases 3%. The major sources of greenhouse gas emissions include transportation (28%), electricity (27%), industry (22%), commercial & residential (12%), and agriculture (10%).

[1] https://www.michigan.gov/whitmer/0,9309,7-387-90499_90704-540278--,00.html
[2] https://www.michigan.gov/documents/mpsc/MPG_Advanced_Planning_11.06.20_707093_7.pdf

For the electricity sector, the path to reducing its own emissions is relatively straightforward: replacing coal and gas plants with carbon-free resources such as wind, solar, and energy efficiency.[3] The carbon intensity of imported electricity should also be considered. Staff's straw proposal sets out guidelines for electric utilities to analyze their emissions, which is a good start.

However, IRP scenarios should also consider the effect that decarbonizing other economic sectors will have on electric utilities. For example, the path toward reducing and eliminating emissions from transportation includes substantial, if not total, electrification of the energy source needed to move people and products. Additionally, buildings in the commercial and residential sector will need to replace propane and gas heating with electrical applications to reduce emissions. The resulting impact on electricity demand can and should be considered in IRPs.

One example from another state is Colorado, which established its statewide greenhouse gas emission reduction goals in 2019. The Colorado Public Utilities Commission is working to incorporate those goals into its integrated resource plan requirements. Under proposed rules for investor-owned utility IRPs, an assessment of the need to acquire resources must address statewide goals to reduce greenhouse gas emissions. This proposal mirrors a requirement finalized earlier this year to address Colorado's statewide goals in IRPs filed by wholesale electric cooperatives. While Colorado's statewide goal is to reduce greenhouse gas emissions 50 percent by 2030, IRPs must include an assessment of reducing carbon dioxide emissions associated with the utility's sales by 80 percent from 2005 levels by 2030.

Additionally, Joint Commenters believe Michigan's filing requirements should be updated to extend the planning horizon out to 2050. Without scenarios that consider the full timeline of the Governor's goals, it is impossible to know if the power sector is on track to meet them.

[3] A note on carbon offsets, which Mr. Jester also addressed in his presentation: Joint Commenters recommend that the MPSC not consider carbon offsets for electric power generation in IRPs. Among other concerns such as inequitable impacts, emission reductions from non-power sectors will increasingly become unavailable as the state approaches net zero economy-wide emissions, and the limited availability of carbon sequestration methods should be reserved for offsetting emissions that are truly difficult to reduce.

2. **For Michigan to meet its 2025 goal, it is likely that the power generation sector would need to achieve a 36% reduction in carbon emissions below 2018 levels.**

Staff's straw proposal does not account for the likelihood that the power generation sector will need to achieve greater than a 28% reduction in CO_2 emissions (from 2005 levels) for the state to achieve that level of reductions economy wide. With respect to the 2025 emission reduction goal, Mr. Jester provided preliminary data and modeling results conducted by Joint Commenters exploring how Michigan might achieve a 28% economy-wide CO_2 reduction. Although the long-term trends (from 1990 to 2018) show declining CO_2 emissions in all sectors, only electric power has changed significantly in the last decade. This is because the decarbonization process for the electricity sector is underway but has not yet begun to any meaningful extent for the transportation, residential, commercial, and industrial sectors.

While policies can be put in place now to stimulate emission reductions in non-electric power sectors, it will take time for the measures to produce results due to the long-lived nature and slow turn over for things like building retrofits, vehicles, and equipment. Thus, for Michigan to meet its 2025 goal, it is likely that the electric power sector will need to drive the bulk of reductions through earlier coal plant retirements and additional expansion of renewable energy resources.[4] To do this, Joint Commenters project that to realistically meet a 28% economy-wide carbon emission reduction goal from 2005 levels by 2025 requires the power generation sector to achieve about a 36% reduction from 2018 levels by 2025.

3. **For Michigan to achieve economy-wide carbon neutrality by 2050, the power sector needs to be zero-emission with transportation and buildings electrified and industrial heat substantially electrified.**

Looking ahead to the 2050 goal, Mr. Jester outlined how achieving economy-wide carbon neutrality requires (1) a zero-emission power sector, (2) nearly complete electrification of both transportation and buildings, and (3) substantial electrification of industrial heat. With respect to the latter two categories, electrification by 2050 requires all-electric equipment sales by about 2035, ramping up to that from 2020. IRP scenarios should incorporate these assumptions about power generation and load growth, and assess how electrified load can be leveraged to integrate further levels of renewables and provide other flexible grid benefits.

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[4] The carbon emission modeling conducted by Joint Commenters does assume a small level of ramp-up in vehicle and building electrification: 8% of vehicle sales are electric by 2025 (currently at about 0.8%) and 100% electrification of 1% of buildings.

4. **The Michigan Integrated Resource Planning Parameters' modeling scenarios, sensitivities, and assumptions should be updated to reflect the state's economy-wide carbon goals and electric utilities' role in achieving them.**

Joint Commenters have prepared suggested edits to Section VIII (Modeling Scenarios, Sensitivities and Assumptions) of the Michigan Integrated Resource Planning Parameters, attached to these comments.

We suggest modifying the Business as Usual scenario to reflect the minimum of what is needed from the power sector to achieve the Executive Directive's 2025 and 2050 carbon reduction goals. The Emerging Technologies scenario should then include more aggressive cost reductions for batteries and modeling of earlier coal plant retirements. The Environmental Policy scenario could then be revised to include a 100% carbon-free standard by 2035, among other changes. Joint commenters suggest this change to maintain the original intent of the Environmental Policy scenario, which is to model more rigorous environmental policies that could potentially be required. A key plank of President-elect Biden's climate and energy plan is establishing a standard for a 100% carbon-free power sector by 2035. While it is uncertain when or if this standard would be enacted, Joint Commenters assert that it should be incorporated into the Environmental Policy scenario to help utilities and the state plan for this potential policy outcome.

* * * *

Thank you for your consideration of these comments.

Suggested Updates to IRP Filing Requirements to integrate Michigan's carbon reduction goals:

Scenario 1. Business as Usual

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7)

The existing generation fleet (utility and non-utility owned) is largely unchanged apart from new units planned with firm certainty or under construction. ~~No carbon regulations are modeled, although some reductions are expected due to age-related coal retirements and renewable additions driven by renewable portfolio standards and goals, as well as economics.~~ **Carbon reductions in the power sector sufficient to meet Michigan's new carbon reduction goals are modeled.**

- **Utilities meet a 36% reduction in carbon emissions below 2018 levels by 2025 and retire all fossil generation by 2050.**
    - **Retirements of all coal units in the utility's fleet should be considered, and those coal units owned by the utility that are not explicitly assumed to retire during the study period shall be allowed to retire in the model based upon economics and/or carbon reduction goals. Retirement of older fuel oil-fired and newer gas fired generation should also be considered in this scenario. Units that are not owned by the utility shall not retire during the study period unless affirmative, public statements to that effect are made by the owner of the generation asset.**
- **All new fossil-fuel-related assets and all maintenance, expansion, and pollution control investments in existing fossil-fueled assets must be depreciated by 2050, with those depreciation schedules reflected in revenue requirements.**
- Natural gas prices utilized are consistent with business as usual projections as projected in the United States Energy Information Administration's (EIA) most recent Annual Energy Outlook reference case.[1]
- Footprint-wide[2] demand and energy growth ~~rates remain at low levels with no notable drivers of higher growth; however, as a result of low natural gas prices, industrial production and industrial demand increases~~ **occurs in line with an electric vehicle sale forecast and electric heating appliance sales forecast through 2050**.
- ~~Low natural gas prices and low economic growth reduce the economic viability of other generation technologies.~~
- Resource assumptions:
    - Resources outside MI – Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO).
    - Resources within MI – Thermal and nuclear generation retirements in the modeling footprint are driven by a maximum age assumption, public announcements, or economics.

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[1] The natural gas price forecast utilized should be consistent with the EIA's most recent Annual Energy Outlook natural gas spot price at Henry Hub in nominal dollars and also including delivery costs from Henry Hub to the point of delivery.

[2] Footprint refers to the Model Region specified in the Michigan IRP Modeling Input Assumptions and Sources, or the State of Michigan plus the applicable RTO region. Larger footprints or Model Regions, if used by the utility, are acceptable.

- Specific new units are modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON) or signed generator interconnection agreement (GIA)).
- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.
- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).
- For all instate electric utilities that are eligible to receive the financial incentive mechanism for exceeding mandated energy saving targets of 1% per year, EWR should be based upon the maximum allowed under the incentive of 1.5% and should be based upon an average cost of MWh saved. The model should include an EWR supply cost curve to project future program expenditures beyond baseline assumptions without any cap.[3]
- For all other electric utilities, EWR should not exceed the mandated targets for electric energy savings of 1% per year and should be based upon an average cost of MWh saved.
- Existing renewable energy production tax credits and renewable energy investment tax credits continue pursuant to current law.
- Technology costs for thermal units and wind track with mid-range industry expectations.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by their respective potential studies.
- Technology costs for ~~solar~~ **<u>generation and battery storage</u>** ~~and other emerging technologies~~ decline with commercial experience[4] **<u>and are informed by pre-IRP request for proposals</u>**.
- Existing PURPA contracts are assumed to be renewed.

Business as Usual Sensitivities:

1. Fuel cost projections
    a. Increase the natural gas fuel price projections from the base projections to at least 200% of the business as usual natural gas fuel price projections at the end of the study period.[5]
2. Load projections
    a. High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the business as usual load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.

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[3] For EWR cost supply curves, see the appendices in the supplemental potential study for the Lower Peninsula at this link: http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf.

<u>[4] Such trends are perhaps best informed by "Mid Technology Cost" scenario in the National Renewable Energy Laboratory's most recent Annual Technology Baseline report.</u>

[5] For example, 200% of the most recent EIA AEO reference case natural gas price is $10.14/MMBtu ($2016) in 2040.

b. If the utility has retail choice load in its service territory, model the return of 50% of its retail choice load to the utility's capacity service by 2023.

3. Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in the Appendix G of the 2017 supplemental potential study for more aggressive potential. EWR savings remain high throughout the study period.
4. Sensitivity allowing only natural gas fired simple cycle combustion turbines to be selected by the model.

Scenario 2. Emerging Technologies

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7)

Technological advancement and economies of scale result in a 35% reduction in costs for demand response, EWR programs, **batteries,** and other emerging technologies.[6,7] For example, costs identified in the demand response potential study should be reduced by 35% **by 2030** for demand response resources. **Significant drop in cost of battery storage spurs more vehicle electrification and renewable development (solar plus storage).** ~~No carbon reductions are modeled, but some reductions occur due to coal unit retirements, and higher levels of renewables, demand response, and energy waste reduction.~~ **Carbon reductions in the power sector sufficient to meet Michigan's new carbon reduction goals are modeled.** Load forecasts and fuel price forecasts remain at levels similar to the Business as Usual Scenario.

- **Utilities meet a 36% reduction in carbon emissions below 2018 levels by 2025 and retire all fossil generation by 2050.**
- Technological advancement and economies of scale result in a greater potential for demand response, energy efficiency, and distributed generation as well as lower capital cost for renewables.
- **Technology advancements in battery storage drive significant cost reductions for that technology.**
    - **Declines in battery cost spur more rapid adoption of electric vehicles and greater deployment of solar (solar plus battery storage).**
- Thermal generation retirements in the market are driven by unit age-limits and announced retirements (consistent with business as usual). Company-owned resource retirements may be defined by the utility, however, ~~a meaningful analysis~~ **modeling** of whether coal units should retire ahead of business as usual dates should be performed. ~~Retirements of all coal units except the most efficient~~ **Earlier retirement dates for each coal unit** in the utility's fleet should be ~~considered~~ **modeled**, and those coal units owned by the utility that are not explicitly assumed to retire during the study period shall be allowed to retire in the model based upon economics **and carbon reduction goals**. Retirement of older fuel oil-fired generation **and newer gas-fired**

[6] Emerging technologies includes, but is not limited to large-scale and small-scale battery storage, **and** large-scale and small-scale solar~~, and combined heat and power~~. See Section IX, Michigan IRP Modeling Input Assumptions and Sources in this document for a full list of potential emerging technologies **that** also could be considered to include as resources with reduced costs in this scenario.

[7] Such trends are perhaps best informed by the "Low Technology Cost" scenario in the most recent National Renewable Energy Laboratory's Annual Technology Baseline.

generation should also be considered in this scenario. Units that are not owned by the utility shall not retire during the study period unless affirmative, public statements to that effect are made by the owner of the generation asset.

- Specific new generating units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario optimizations considering the current resources in the MISO generation interconnection queue.
- Prior to and during the modeling process, the utilities shall take into account resources that include, but are not limited to: small qualifying facilities (20 MW and under), renewable energy independent power producers, large combined heat and power plants, and self-generation facilities such as behind-the-meter-generation (btmg) as more fully described in section IX, Michigan IRP Modeling Input Assumptions and Sources.
- Existing renewable energy production tax credits and renewable energy investment tax credits continue pursuant to current law.
- Technology costs for thermal units remain stable and escalate at moderate escalation rates.
- Technology costs for EWR and demand response programs will be reduced 35% from the level determined by their respective potential studies.
- **Technology costs for heat pumps and geothermal for building electrification are reduced.**
- ~~Technology costs for energy storage resources decline over time, particularly battery technologies and others which can enable supply- and demand-side resources.~~
- Existing PURPA contracts are assumed to be renewed.

Emerging Technologies Sensitivities:

1. Fuel cost projections
   a. Increase the natural gas fuel price projections from the base projections to at least 200% of the business as usual natural gas fuel price projections at the end of the study period.[8]
2. Load projections
   a. High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.
3. Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in Appendix G of the 2017 supplemental potential study for more aggressive potential.[9] EWR savings remain high throughout the study period.

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[8] For example, 200% of the most recent EIA AEO reference case natural gas price is $10.14/MMBtu ($2016) in 2040.

[9] For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf;

4. Increase the use of renewable energy in the utility's service territory to at least ~~25~~**30**% by 20**25**~~30~~.

Scenario 3. Environmental Policy

(Applicability: Utilities located in MISO Zone 7)

Clean energy goals targeting 100 percent carbon-free power sector by 2035 are enacted.[10] All coal generation is retired by 2030. Rapid increases in adoption of electric vehicles occur due to decreased cost in batteries and adoption of zero emission vehicle goals with all new sales of vehicles being electric by 2035. Increased renewable additions are driven by carbon-free standard, extension of tax credits, and economics. Increases in the electrification of heating and buildings drives energy and demand growth; all new building equipment sales being electric by 2035. ~~Carbon regulations targeting a 30% reduction (by mass for existing and new sources) from 2005 to 2030 across all aggregated unit outputs are enacted, modeled as a hard cap on the amount of carbon emissions, driving some coal retirements and an increase in natural gas reliance. Increased renewable additions are driven by renewable portfolio standards and goals, economics, and business practices to meet carbon regulations.~~

- Demand and energy growth rates are modeled at a level equivalent to a 50/50 forecast and are consistent with the business as usual projections. **Load increases due to increased adoption of electric vehicles and increased electrification of buildings, including replacement of propane and heating oil with heat pumps.**
- Natural gas prices utilized are consistent with business as usual projections as projected in the EIA's most recent Annual Energy Outlook reference case.[11]
- Current demand response, energy efficiency, and utility distributed generation programs remain in place and additional growth in those programs would happen if they are economically selected by the model to help comply with the specified carbon**-free standard** ~~reductions~~ in this scenario.
- Non-nuclear, non-coal generators will be retired ~~in the year the age limit is reached and driven by announced retirements~~ **no later than 2035 based on the carbon-free standard**. Coal units ~~will primarily be retired based upon carbon emissions and secondarily based upon economics~~ **will retire no later than 2030 based on mandate**. Nuclear units are assumed to have license renewals granted and remain online.
- Specific new units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.

See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

[10] **Carbon-free is defined as non-carbon-emitting electric generation and electricity from renewable resources.**
[11] The natural gas price forecast utilized should be consistent with the EIA's most recent Annual Energy Outlook natural gas spot price at Henry Hub in nominal dollars and also including delivery costs from Henry Hub to the point of delivery.

- Tax credits for renewables continue until 2022 to model existing policy.
- Technology costs for wind, solar and other renewables decline with commercial experience and forecasted at levels ~~35%~~ lower than in the ~~business as usual case~~ **emerging technologies case based on accelerated deployment and learning**.
- Non-carbon dioxide emitting resources will be increased, due to the ~~constraint on allowable carbon emissions in the model~~ **carbon-free standard**.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by their respective potential studies.
- Existing PURPA contracts are assumed to be renewed.
- ~~Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).~~

Environmental Policy Sensitivities:

1. Fuel cost projections
   a. Increase the natural gas fuel price projections from the base projections to at least 200% of the business as usual natural gas fuel price projections at the end of the study period. 30
2. Load projections
   a. High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.
3. ~~50% carbon reduction in the utility's service territory, modeled as a hard cap on the amount of carbon emissions, by 2030 as a sensitivity~~.
4. Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in the 2017 supplemental potential study for more aggressive potential.[12] EWR savings remain high throughout the study period.

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[12] For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula,
http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf;
See also supplemental potential study for the Upper Peninsula,
http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

November 25, 2020

Dear Ms. Rogers,

Thank you for the opportunity to provide feedback on the Michigan Public Service Commission Staff ("Staff") Strawman Proposal for satisfying Executive Directive ("ED") 2020-10, issued on October 21, 2020, and the alternative proposals presented by 5 Lakes Energy (on behalf of the Ecology Center, Environmental Law and Policy Center ("ELPC"), Michigan Environmental Council, National Resource Defense Council, Sierra Club, Union of Concerned Scientists, and Vote Solar), Indiana Michigan Power, and ELPC (on behalf of the same parties as represented by 5 Lakes Energy) in the Advanced Planning Stakeholder Workgroup sessions.

Staff's Strawman Proposal

Staff proposed multiple options to amend the currently-approved Michigan Integrated Resource Planning Parameters ("MIRPP") and Integrated Resource Plan ("IRP") filing requirements depending upon whether a utility is filing an IRP prior to the year 2023 or after.

For utilities filing IRPs prior to 2023, Staff: (i) proposed no modifications to the current MIRPP, (ii) recommended that an addendum be added to the filing IRP requirements, and (iii) identified two emissions reporting options, Option 1 and Option 2, as shown in Figure 1.

The Company is supportive of not modifying the MIRPP and IRP filing requirements for utilities filing IRPs prior to 2023 because of the lengthy 12-to 18-month IRP development process, which would be further challenged by the timing of any of the new requirements adopted by the Commission in this proceeding.

The Company is supportive of the emissions reporting options shown in Figure 1, as offered by the Staff. Emissions charting is currently included in the IRP filing requirements to some extent, and minor modification is needed to accommodate the below reporting requirements. The Company's position is that the charting of emissions should be applied to the utility's generating fleet to better align with those emissions that are under the direct control of the utility. Utilities should not be required to chart emissions occurring in other sectors, or emissions occurring outside of the utility's direct control. External risk areas that occur in other sectors or occur outside the direct control of the utility, but still impact utility planning of resources, can be handled within the design of scenarios, sensitivities, and risk analysis in order to support utility business decisions within their scope of control or responsibility.

Figure 1

Option 1	Option 2
No MIRPP Update but Commission order directing addendum to filing requirements.	
Charts Carbon out to 2025 compared to 28% Carbon reduction.	Charts Carbon out to the 15-year planning horizon to illustrate the path toward 2050 and highlighting when the utility achieves a 28% reduction.
Spreadsheet of CO2, SOx, NOx, Mercury, and PPM for each year of the 15-year planning horizon for the utility's preferred plan and each MIRPP scenario optimized plan.	

For IRPs filed in or after the year 2023, the Staff identified four different options for incorporating emissions reporting requirements into IRPs, as shown in Figure 2. These options require changes to the MIRPP and IRP filing requirements approved in Case No. U-18418 and U-18461. The Company recommends changes and improvements to these requirements that both address the Governor's ED-2020-10 and enhance the value of a utility's IRP.

Figure 2

Option 1	Option 2	Option 3	Option 4
Requires MIRPP ***BAU*** scenario change to include carbon goal of 28% reduction by 2025 as a sensitivity.		Requires MIRPP change to ***all*** scenarios reflecting the Carbon goal of 28% reduction by 2025 as a sensitivity.	Requires MIRPP change to all scenarios reflecting Carbon Neutrality by 2050 and therefore modeling as a sensitivity.
If the utility preferred plan does not comply with the 2025 goal, include an optimized alternative plan that does comply with the 2025 goal and compare to the preferred plan.			If the utility preferred plan does not comply with the 2050 goal, include an optimized alternative plan that does comply with the 2050 goal and compare to the preferred plan.
Charts Carbon out to 2025.	Charts Carbon out to the 15-year planning horizon to illustrate a path toward 2050.		Charts Carbon out to 2050 in Exhibit to illustrate goal.
Spreadsheet of CO2, SOx, NOx, Mercury, and PPM for each year of the 15-year planning horizon for the utility's preferred plan and each MIRPP scenario optimized plan.			Spreadsheet of CO2, SOx, NOx, Mercury, and PPM for each year out to 2050 for the utility's preferred plan and each MIRPP scenario optimized plan.

The Company supports Staff's Options 1 and 2. The Company recommends that Options 1 and 2 be applied consistently for IRPs filed pre- and post-2023. That is, if Option 1 is recommended for IRPs pre-2023, then Option 1 should be chosen for post-2023 IRPs. The charting of emissions for each of these options should be those emissions in the direct control of the utility, as stated above for pre-2023 IRPs. Option 1 and 2 support ED-2020-10 by applying a carbon reduction sensitivity to the Business as Usual ("BAU") scenario, which is designed to represent the base view of the world and therefore is the most appropriate and valuable scenario in which to apply the sensitivity.

Option 3 asks for the carbon reduction of 28% by 2025 as a sensitivity for all scenarios. The Company is not supportive of running sensitivity analysis across all scenarios in a utility's IRP if it does not give additional insight or value to the IRP process. The design of each scenario is an important factor to consider in determining whether a sensitivity analysis should be conducted or not. It is the Company's position that the current MIRPP scenarios are nearly identical and represent more of a sensitivity analysis versus truly different scenarios. For example, load forecasts are identical in all three scenarios, leaving no ability to incorporate potential changes in load due to electric vehicle growth, behind the meter growth, or other changing market conditions. This results in an over production of information that does not provide value to the utility planning and decision-making process. Singular changes to all scenarios as currently written, such as the carbon reduction analysis proposed in Option 3, would not provide additional insight.

Option 4 requires a nearly 30-year optimization plan be created for forecasts and assumptions that are already increasing in uncertainty by the end of the current 20-year horizon of an IRP. The Company does not support Option 4 and its requirements for modeling, optimized plans, carbon and other emissions tracking to 2050. This requires a significant amount of additional modeling, including formal sensitivity modeling and an alternative optimized plan that achieves carbon neutrality by 2050, potentially using technologies that are in their infancy and are lacking the necessary cost information to appropriately optimize. The Company's position is that modeling carbon neutrality by 2050 yields no additional value given the level of uncertainty. Solving for a future scenario that may trigger up front investments is not prudent and is unreasonable. Indeed, MCL 460.6t requires a utility to provide a 5-year, 10-year, and 15-year projections, and requires a minimum 5-year review of utility IRPs versus a 20- or 30-year projection. The current 20-year optimizations and 5-year reviews, as required by statute and Commission order, are sufficient to provide the necessary information in long-term resource planning, and the objectives of the Governor's ED-2020-10.

To address issues in the current MIRPP while still working to provide a level of analysis in support of the Governor's ED-2020-10 and integrated planning, the Company recommends at a minimum the following changes to the MIRPP for IRPs filed post-2023. The Company also recommends continued discussion to further develop these changes:

1. Retain the BAU case with the addition of a formal carbon sensitivity to achieve the 28% carbon reduction goal by year 2025 for the utilities generating fleet. In addition:
    a. Replace the requirement to use the most recent Energy Information Administrations – Annual Energy Outlook for natural gas prices in all three existing MIRPP scenarios with a more flexible requirement that provides the opportunity for the utility and stakeholders to assess multiple business as usual forecasts offered by various industry sources to determine the most accurate natural gas price forecast. The setting of current requirements has caused duplication of work to ensure accurate results for major decision-making processes that further taxes the already lengthy and complex process of developing an IRP.

    b. The requirement to model the Statewide Potential Studies for Energy Waste Reduction and Demand Response programs in all three scenarios should be modified to require the utility to use these studies to ***inform*** the IRP development, and then give a utility the choice to decide to use the results for its IRP. Determinations in potential levels of savings, and the associated costs to achieve those savings, needs to be specific and tailored to each specific utility's operations and customer base. It remains the responsibility of the utility to provide thorough and reasonable justification for the accuracy and comprehensiveness of their potential study as part of the regulatory case. This modification to utilize a utility's potential study is not intended to reduce transparency to stakeholders. The Company continues to support continued stakeholder engagement through this process and believes the current requirements on stakeholder engagement are sufficient to drive this.

    c. Recommend removal of either the Environmental Policy or Emerging Technologies scenario(s), with the remaining one of these scenarios modified to reflect a potential future that has multiple assumptions different from the BAU scenario. This new scenario should create a narrative assuming advancements in technologies related to electrification (heating and transportation), decarbonization, customer participation in generation such as behind the meter generation, and changes in the levels and shape of demand over the study period. The parameters of this scenario would drive reductions in the level of capital cost for selected resources, as well as other inputs.

    d. Recommend cost reductions for renewables, Energy Waste Reduction, and Demand Response programs (currently 35% cost reductions in the Emerging Technologies scenarios and a slight modification of these levels in the Environmental Policy scenario) be less prescriptive. The Company suggests a requirement for the non-Business as Usual scenario to stress test capital cost reductions of these resources based upon leading market indicators and technology advancements.

It is the Company's position that requiring two scenarios, with the high-level modifications noted above, will give a broad view of potential risks to a utility's resource plan, and support the cycle of decision making that MCL 460.6t facilitates. This approach provides greater agility to identify changing market and industry conditions that will impact long-term resource plans because a utility will have the ability to design additional scenarios or sensitivities more representative of future market conditions occurring in-between the filing of its IRPs. Continued stakeholder engagement is a valuable avenue to obtain more frequent feedback and thinking into utility IRPs, as opposed to prescriptive requirements defined in MIRPP parameters.

Alternative Proposals from Stakeholders

Finally, there were two alternative proposals presented during the November 6th Advanced Planning Stakeholder Workgroup. Various stakeholder groups, represented by 5 Lakes Energy, presented recommendations that create an assumed scenario with set levels of Energy Waste Reduction, specific accelerated retirements of thermal units, and defined increased penetration of renewables by 2025.

The Company does not support this alternative, as it is too prescriptive. It creates assumptions around specific utility retirements, forecasts, and other areas that are more appropriate for individual utilities to develop and utilize for decision making. It is most appropriate for each utility to define the best way to meet emission reduction targets and carbon neutral goals within the currently-defined IRP process, and to determine which methods and plans of emissions reductions are best for that utility's customer base.

As for incorporating electrification into electricity demand forecasts, this is a continually evolving element with no current formal targets around electrification. Therefore, it is not appropriate to include in base electric demand forecasts for this proposed scenario. The Company supports the recommendation to work to develop industry-specific electrification forecasts for future incorporation in demand forecasts within the utility IRP process, but maintains that it is most appropriate to utilize sensitivity analysis to best determine the effects of electrification in IRP planning, as opposed to inclusion in the base demand forecast.

The alternative scenario also recommends that carbon offsets not be considered. The Company does not support this restriction this early in the transition to carbon neutrality and believes it is best to include a variety of options as utilities continue to drive towards carbon emission reductions targets. In addition, the Governor's goal presupposes the use of offsets, as the goal is for *net*-zero emissions, and not just zero emissions. For example, the Michigan Department of Natural Resources is in the process of the potential creation of an offset program using state-owned land. Particularly considering that offset programs can be major drivers of improving our State's natural areas and wildlife populations, the Commission should not at this point take this potentially important tool off the table.

With respect to the recommendations made regarding Scope 1, 2, and 3 emissions, the Company supports providing estimated projections of its emissions from its owned units, units under a power purchase agreement (PPA), and Midcontinent Independent System Operator (MISO) purchases. These types of emissions include Scope 1 (from owned units) and Scope 3 (from PPA and MISO units), but not Scope 2.[1] The Commission should, however, limit its use of such data to areas within its jurisdiction in the IRP process, as the Governor's net-zero goal announcement does not change the Commission's jurisdiction and the Commission is not a carbon regulator.

Specifically, the Commission should focus its analysis on the units that produce Scope 1 emissions, as utilities only control or have direct authority over these units. The Company is unable to identify, let alone control, units that produce Scope 3 emissions associated with MISO-related purchases. Rather, the Company purchases from MISO a generic MWh of energy or a MW of capacity, not from a specific unit. Without unit-specific information, accurate calculation of Scope 3 emissions is difficult, particularly over the 10, 15, and 20-year periods considered in utility IRP filings. In addition, no consistent or established method exists in the utility industry for estimating the carbon emissions associated with energy market transactions, as documented by a recent EPRI paper that identified five different methods but was unable to recommend a single best option.[2] As such, while the Company is comfortable providing estimates of Scope 3 emissions associated with its MISO-related purchases, it is inappropriate to use such estimates in decision making. Scope 3 emissions should be considered for informational purposes only, and not for decision making purposes.

In reviewing the overall recommendations provided by 5 Lakes Energy, Staff and the Michigan Public Service Commission ("Commission") should be mindful of the fact that stakeholders will continue to have the opportunity to intervene in future utility IRP proceedings. The Commission should not create new IRP parameters or IRP filing requirements which force utilities to pursue policy objectives for certain stakeholders when those stakeholders will have the opportunity to advance their policy objectives in future utility IRP proceedings.

[1] Scope 2 includes emissions related to electricity, heat, or steam used by a company that is purchased from another party. For example, if the Company had a service center in DTE Electric's service territory, and purchased the electricity for that facility's use from DTE, then emissions associated with that purchase of electricity would fall under Scope 2. While such emissions exist, they are a very small portion of the Company's overall emissions profile. In addition, they relate to an activity – the use of electricity, rather than its generation – outside of the scope of the MIRPP.

[2] Please see https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf.

The second alternative proposal was made by Indiana Michigan Power. This alternative proposal recommends the inclusion of a comprehensive stakeholder process, maintaining a consistent planning horizon, filing of an IRP every three years, and consideration of future changes in technologies/fuel sources as components of incorporating carbon emission reduction planning into the current process. The Company is in support of these elements as part of a comprehensive integrated resource planning process and has already taken steps to satisfy them by filing an IRP every three years and utilizing an existing comprehensive stakeholder process that is well-positioned to also incorporate carbon emissions reduction discussions and feedback.

Integrated Planning Comments

The Company's position on integrating transmission and distribution planning with IRPs is that the existing requirements suffice in the development of IRPs, with a future goal to continue the journey of integration.

For the technology options and the associated operating characteristics considered in IRPs, value and costs are primary integration points between wires and supply-side planning. The technology options offered in an IRP, whether as a Non-Wires Alternative ("NWA"), a Distributed Energy Resource ("DER"), or transmission-connected resource, will naturally create an integration of wires and supply. The Company is currently well positioned to support a natural integration, with changes to its organizational structure, to create an environment of alignment in planning efforts.

The Company supports the idea of feeding applicable information from a Distribution Plan into the IRP, and vice versa. This can be achieved with a requirement for utilities to consider and incorporate, where applicable, distribution planning information to help inform an IRP. Leaving room for flexibility on these requirements drives an expedient process by minimizing the barriers and constraints that a prescriptive regulatory process creates.

The Company recommends a path forward that distinguishes between near-term actions and planning versus long-term actions and planning. Near-term and long-term each of require a different approach to achieving the ultimate goals of cost-effective, clean, and reliable energy for Michigan. Suggestions or recommendations such as providing a listing of substations, noting optimal locations for the siting of resources, and making changes to investments in the wires system that are beyond the interconnection of supply-side resources are all near-term processes that can continue to be addressed in distribution plans as opposed to the long-term planning of an IRP.

It is too early in the process of integration for specific requirements to be put in place for formal integration of transmission planning and integrated resource planning. Further alignment with existing MISO processes, such as MISO model development, MISO Transmission Expansion Planning (MTEP), and MISO Generator Interconnection and Retirement processes is required before the benefits of formal integration of transmission planning into integrated resource planning can be fully realized. The present timing cycle of integrated resource planning has not allowed this alignment to take place. In addition, there are still a number of inputs required to perform a transmission or distribution system analysis that are either unknown at the time where assumptions need to be made, such as generator siting assumptions, or outside of utility control, such as resource decisions made by other utilities inside and outside MISO Local Resource Zone (LRZ) 7. Continued alignment with MISO, development of requirements through a robust stakeholder process, and flexibility will result in the most valuable integration of transmission planning and resource planning.

Closing

The Company appreciates the opportunity to provide these comments regarding this important topic. We look forward to continuing to work with the Staff, Commission and other stakeholders on these matters.

Respectfully submitted,

Consumers Energy Company