OLSON, BZDOK & HOWARD

October 28, 2021

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-Filing

RE: MPSC Case No. U-21090

Dear Ms. Felice:

The following is attached for paperless electronic filing:

PUBLIC Direct Testimony of Tyler Comings on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club;

Exhibits MEC-15 through MEC-40; and

Proof of Service.

NOTE: A CONFIDENTIAL version of Testimony and Exhibits will only be served upon those with a signed NDA on file

Sincerely,

Digitally signed by Lydia Barbash-Riley
Date: 2021.10.28 11:35:59 -04'00'

Lydia Barbash-Riley
lydia@envlaw.com

xc: Parties to Case No. U-21090

STATE OF MICHIGAN

MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief	)))))	U-21090 ALJ Sally L. Wallace

PUBLIC

DIRECT TESTIMONY OF TYLER COMINGS

ON BEHALF OF

MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, AND SIERRA CLUB

October 28, 2021

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 1012 Massachusetts Avenue, Arlington, Massachusetts.

Q. Please describe Applied Economics Clinic.

A. The Applied Economics Clinic is a 501(c)(3) non-profit consulting group formerly housed at Tufts University's Global Development and Environment Institute. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC), and Sierra Club (SC), collectively referred to as "MNS."

Q. Please summarize your work experience and educational background.

A. I have 15 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony on these topics in Arizona, Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New Mexico, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst

(CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided expertise for many public-interest clients including: American Association of Retired Persons (AARP), Appalachian Regional Commission, Citizens Action Coalition of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Massachusetts Division of Insurance, Michigan Agency for Energy, Montana Consumer Counsel, Mountain Association for Community Economic Development, Nevada State Office of Energy, New Jersey Division of Rate Counsel, New York State Energy Research and Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont Department of Public Service, West Virginia Consumer Advocate Division, and Wisconsin Department of Administration.

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42 and conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group (now EBP).

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Exhibit MEC-15.

Q. Have you previously testified before the Michigan Public Service Commission?

A. Yes, on five occasions. Most recently, I testified in Consumers Energy Company's ("Consumers" or "the Company") 2021 rate case (No. U-20963) and its 2020 rate case (No. U-20697). In January of 2020, I submitted testimony on the Indiana Michigan Power Company (I&M) Integrated Resource Plan (IRP) in Case No. U-20591. In 2018, I submitted testimony on Consumers' 2018 IRP (No. U-20165) and testified in Consumers' 2018 rate case (No. U-20134).

Q. What is the purpose of your testimony?

A. My testimony examines the Company's selection of its proposed course of action (PCA), with a focus on one of the major resource decisions in the PCA: the Company's proposal to purchase four natural gas plants ("gas acquisition"). I discuss the Company's procurement process that led to the consideration of the four plants, and Consumers' modeling approach for the gas acquisition. I also explain why two of these gas plants – Dearborn Industrial Generation (DIG) and Kalamazoo, both owned by a corporate affiliate of the Company – carry heightened risks for Consumers and its customers.

After discussing these concerns, I present alternative modeling of portfolios which address flaws in the Company's approach. These alternative portfolios include much of the gas capacity that the Company wishes to buy, while omitting the riskier DIG and Kalamazoo plants. Broadly, there are two types of alternative portfolios that I present: 1) a portfolio that includes short-term capacity purchases as-needed and 2) a portfolio that relies on newly built resources to serve capacity need. Finally, I discuss transition planning for the Karn and Campbell fossil plants, which are proposed for retirement in 2023 and 2025, respectively.

Q. What information did you review in preparing your testimony in this case?

A. I reviewed the Company's testimony, exhibits, workpapers, discovery responses, and modeling outputs. I also worked with MNS witness George Evans on developing alternative portfolios, which he modeled in Aurora (the same model software used by Consumers).

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I sponsor Exhibits MEC-15 to MEC-40:

MEC-15:	Comings Resume
MEC-16:	MEC-CE-237
MEC-17:	AG-CE-388
MEC-18:	MEC-CE-003 + "MEC-CE-003 Public" folder, "Attachment 3" sub-folder, Request_for_Proposal_Consumers_RFP
MEC-19C:	"MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 1" sub-folder, CMS Enterprises CE Asset RFP Response
MEC-20C:	MEC-CE-083-CONF
MEC-21C:	"MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 4" sub-folder, NPV Model- Dearborn, NPV Model- Kalamazoo
MEC-22C:	MEC-CE-236 (CONFIDENTIAL)
MEC-23C:	MEC-CE-472-CONF
MEC-24:	MEC-CE-040 + MEC-CE-046
MEC-25:	AG-CE-368 + ST-CE-400
MEC-26:	2021/2022 Planning Resource Auction (PRA) Results (Apr. 15, 2021) + U20963-MEC-CE-017-Hugo_ATT_1
MEC-27:	Case No. U-20697, discovery response U20697-MEC-CE-033
MEC-28C:	MEC-CE-060-CONF, MEC-CE-060-CONF (Partial) + U21090-060-CONF-Walz_CONF_ATT_2

MEC-29:	West Virginia Public Service Commission, Case No. 17-0296-E-PC, Direct Testimony of Tyler Comings (excerpt)
MEC-30C:	"MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 2" sub-folder, pre-qual
MEC-31C:	MEC-CE-482, U21090-MEC-CE-482 Att5 Covert Plant Modeling RFP fixed costs CONFIDENTIAL, and U21090-MEC-CE-482 Att6 Dearborn_Kzoo_Liv Plants Modeling RFP fixed costs CONFIDENTIAL
MEC-32C:	MEC-CE-239 (Confidential)
MEC-33:	MEC-CE-066
MEC-34C:	"MEC-CE-003-Supp-CONF-Attachments" folder, "3c. Emails" sub-folder, "Other Communications" sub-folder, "CMS" sub-folder, [[[redacted]]]
MEC-35:	MEC-CE-058 + U21090-MEC-CE-058-Kapala_ATT_2
MEC-36:	U20963-MEC-CE-659
MEC-37:	U20697-MEC-CE-549, U20697-MEC-CE-1029, U206963-MEC-CE-028
MEC-38:	MEC-CE-089, 090
MEC-39C:	U21090-MEC-CE-089-Kapala_CONF_ATT_2
MEC-40:	ST-CE-172, 271, 272, 273

Q. Please summarize your findings and recommendations.

A. Based on my review and analysis, I conclude that:

1. **Consumers has not met its burden to show that the gas acquisition is in the public interest. This is for several reasons:**

    a. **The Company's solicitation process was too narrow and uncompetitive.** Consumers issued an RFP that only sought the full ownership of existing gas units in MISO Zone 7, rather than seeking a wide array of resource and ownership options as other utilities commonly do. This narrowly defined RFP yielded only four qualified plants in response. Consumers then decided to buy all of those qualified plants. Given the design of the solicitation, the Company did not have anything else from which to choose.

b. The RFP administrator's analysis of the gas plants does not address [[[redacted] **]]** Consumers selected Charles River Associates ("CRA") to administer the RFP. This consultant's NPV analysis considered the plants from a [[[redacted]]].

c. The Company's IRP modeling treated the plants as an all-or-none proposition. The Company's approach to the gas acquisition has been one that shut out other resource options to the four gas plants, including by failing to model acquisition of individual plants or other subsets of the four plants.

2. There are substantial risks that are specific to the DIG and Kalamazoo plants.

The DIG plant is subject to the risks of environmental regulations and fuel cost risks. [[[redacted]]] DIG and Kalamazoo also carry roughly [[[redacted]]] the fixed costs as Covert and

Livingston, making them a heavier burden to carry for any owner. The projected capital costs at Kalamazoo are likely [[[redacted]]] by both CRA and Consumers.

3. **The Company should pursue a resource portfolio that is lower cost and lower risk than the PCA.** Under the PCA, Consumers would purchase more than 2 GW of natural gas plants in the short-term, thereby planning to lock in a large portion of the Company's energy system into natural gas until at least 2040. In my testimony below, I present two main alternatives to the PCA that would provide capacity for the Company's customers at a lower cost and with less risk. These portfolios would include approximately 1,200 MW of additional gas capacity but omit the DIG and Kalamazoo plants. One alternative would include short-term capacity purchases (bilateral contracts) when needed, along with similar solar and battery buildouts to the PCA; this plan provides cost savings relative to the PCA under both the Consumers gas price forecast and the Energy Information Administration's Annual Energy Outlook (AEO) gas price. The other alternative would build new battery storage earlier than the PCA but end up with similar levels of battery storage and solar as the PCA in 2040; this plan is cheaper than the PCA under many of the gas price forecast and planning scenarios. Both plans provide better protection from critical risks such as fuel costs, technology costs, and carbon regulation than the PCA.

4. **The community transition plan for Karn's retirement should be prioritized, and transition planning for Karn and Campbell should be transparent.** In 2018, the Company developed a community transition plan for the retirement of Karn units 1 and 2 in 2023, but the Company [[[redacted]]

[redacted]]], and the plan has not been updated. Consumers is now proposing retirement of the Karn 3 and 4 oil/gas peaking units, meaning that all four Karn units may retire in 2023. Yet it is unclear if the Company will await a final decision in this case before moving forward with transition planning. That would be a mistake, because the planned retirement date will come less than a year after this case concludes. Consumers should also make its community transition plan publicly available, which it has yet to do. Finally, the Company should engage in a robust and transparent transition planning process for the Campbell coal plant, which is proposed for retirement in 2025.

II. SUMMARY OF CONSUMERS' PROCUREMENT AND MODELING PROCESSES THAT LED TO ITS PROPOSED COURSE OF ACTION

Q. Please summarize this section of your testimony.

A. In this section, I summarize the Company's decision-making regarding the Proposed Course of Action (PCA), with a focus on the Company's request to acquire approximately 2 GW of gas capacity at a total cost of $1.345 billion.[1] First, I briefly describe the PCA and the four gas plants. Second, I summarize the general modeling approach that the Company took in developing this IRP. Third, I discuss the procurement process that led to the gas acquisition decision, including the request for proposals (RFP) and evaluation of the plants

[1] Revised Direct Testimony of Richard T. Blumenstock, pp. 6-7. Note: my testimony includes some references to testimony and exhibits from Consumers' 2020 and 2021 rate cases, No. U-20697 and U-20963. Record citations from those cases are identified by the case number. Unless otherwise noted, citations to witness testimony, exhibits, and discovery responses are referring to this case.

done by the Company's contractor Charles River Associates ("CRA"). Finally, I discuss how the Company incorporated the four gas plants into its own modeling and PCA.

Subsequent sections of my testimony discuss the flaws in the Company's construction of the PCA, and the risks of acquiring the DIG and Kalamazoo plants. I also present alternative portfolios that include some of this additional gas capacity, but would exclude DIG and Livingston, thereby reducing costs and risk to ratepayers.

Q. Please summarize Consumers' Proposed Course of Action (PCA).

A. The Company's PCA addresses capacity needs that it anticipates through 2040, but the major resource decisions, and Consumers' cost recovery requests, focus on planned unit retirements and plant acquisitions through 2025. The Company's capacity needs and supply are defined in terms of Zonal Resource Credits (ZRCs), which account for forced or random outages at the resource—also referred to as unforced capacity, or "UCAP."[2] In the short-term, the decisions to retire Karn 3 and 4 in 2023 and Campbell 1-3 in 2025 create capacity needs in those years, requiring decisions for replacement resources in this case. To that effect, the PCA includes the acquisition of 1,114 ZRCs of existing natural gas generation in 2023 followed by additional gas plant capacity in 2025 increasing the new gas capacity to 1,942 ZRCs by 2033;[3] the retirement of Karn units 3 and 4, which are oil/gas peaking units, in 2023 (769 ZRCs); and the retirement of the Campbell coal units

[2] More specifically, ZRCs are the unit of capacity accreditation in MISO. These values are based on the likelihood of the unit being available to meet peak demand.

[3] This includes four gas plants: 1114 ZRCs for the Covert plant in 2023, 75 ZRCs for the Kalamazoo plant in 2025, 114 ZRCs for the Livingston plant, and 728 ZRCs at the Dearborn Industrial Generation (DIG) plant. The DIG capacity increases over time due to it having previously sold capacity to other parties.

1-3 in 2025 (1,346 ZRCs). There are also solar photovoltaic (PV) additions starting in 2025 and incrementally added throughout the modeling period – totaling 3,009 ZRCs of solar. The Company also starts adding battery storage in the 2030s, finally reaching 450 ZRCs of battery storage in 2040. There are also demand-side management resources in the plan, including 99 ZRCs of demand response, and 213 ZRC's of energy waste reduction (EWR).[4]

Q. Please provide more detail on the Company's proposed acquisition of existing gas plants.

A. The Company's PCA includes the acquisition of four natural gas plants:

- **Covert** – a 1,176 MW[5] combined-cycle natural gas plant built in 2004 and located in Covert, Michigan. Covert is currently owned by New Covert Generating Company and serves the PJM market. The Company proposes to buy the plant in 2023 for $815 million.[6]
- **DIG –** a 770 MW simple cycle and combined cycle natural gas plant finished in 2001 and located in Dearborn, Michigan. The plant runs on natural gas and blast furnace gas; it is owned by Consumers' unregulated affiliate CMS Enterprises Company (CMS). Consumers proposes to purchase DIG along with the two plants shown below (Kalamazoo and Livingston) in 2025 for $530 million.[7]

[4] Blumenstock Revised Direct, p. 64, Figure 9.

[5] The reported capacity of these plants is expressed in installed capacity (ICAP). The capacity that these gas plants would provide to Consumers – i.e., the plants' ZRCs – is lower.

[6] Direct Testimony of Jeffrey E. Battaglia, p. 31.

[7] Battaglia Direct, p. 38.

- **Kalamazoo –** a 75 MW simple-cycle gas plant built in 1999 and located in Comstock, Michigan.[8]

- **Livingston -** a 156 MW simple-cycle gas plant built in 1999 and located in Gaylord, Michigan.[9]

For purposes of this IRP, Consumers assumed that the plants would all retire on May 31, 2040.[10]

Q. Please summarize the modeling process the Company employed in this IRP.

A. The Company initially modeled the potential retirement of the Campbell coal units and Karn 3 and 4 oil/gas peaking units, as well as portfolio modeling. Under the settlement agreement for the 2018 IRP case (No. U-20165), this IRP was required to analyze the potential retirement of Campbell units 1 and 2 in 2024, 2025, 2026, 2028, and 2031.[11] When the Company conducted that analysis, it showed substantial savings from retiring Campbell 1 and 2 in 2025.[12] The Company also discussed myriad reasons for retiring coal units, including 1) increasing regulatory pressure on coal (such as the state's emissions goals); 2) the Company's own net-zero carbon goal; 3) concerns about the units' age and

---

[8] Battaglia Direct, p. 36.

[9] Battaglia Direct, p. 37.

[10] Blumenstock Revised Direct, pp. 53-54; see also Direct Testimony of Sara T. Walz, p. 67 (noting that "the purchased gas units are assumed to cease operations by May 31, 2040").

The Company noted, however, that these retirement dates could change in future IRPs. Blumenstock Revised Direct, pp. 53-54. It implied that these plants could run after 2040 depending on "the evolution of cleaner technologies, the possibility of carbon sequestration technologies, and potential for carbon offsets." Blumenstock Revised Direct, p. 59.

[11] Case No. U-20165, June 7, 2019, Order Approving Settlement Agreement, Exhibit A, Para. 4.

[12] Blumenstock Revised Direct, p. 66, Figure 10.

reliability; and 4) investors' increasing demands for coal-free generation. In light of this landscape, and the retirement savings modeled by Consumers, it concluded that it should accelerate the retirement of Campbell unit 3 and retire all three Campbell units in 2025.[13] The Company also modeled the 2025 retirement of Karn units 3 and 4, which are currently scheduled to retire in 2031, and estimated savings in most scenarios run.[14] The Company ultimately proposed to retire Karn 3 and 4 in 2023—at the same time as Karn units 1 and 2 retire.[15] The final PCA includes these retirement dates for Campbell and Karn units.

As part of the current IRP, the Company conducted modeling using the Aurora model and projected its planning reserve margin requirement (PRMR),[16] or its necessary capacity level. The Company modeled the following scenarios and sensitivities: 1) a business-as-usual (BAU) scenario with the Company's base case assumptions; 2) an Emerging Technologies (ET) scenario which assumes lower costs for renewable, storage, and demand-side management options; 3) an Environmental Policy (EP) scenario which assumes a 30 percent reduction in carbon emissions from 2005 levels by 2030; 4) a Carbon Reduction scenario that uses the EP scenario but assumes a higher peak load due to electrification; and 5) an Advanced Technology (AT) scenario which assumes higher

[13] Blumenstock Revised Direct, pp. 15-19.

[14] Blumenstock Revised Direct, p. 66, Figure 10.

[15] Blumenstock Revised Direct, pp. 29-30, 53. The Company has a net zero carbon goal for 2040 and Governor Whitmer has set goal to reduce carbon emissions by 28 percent of 2005 levels in 2025 and for the state to reach carbon neutrality no later than 2050. See https://www.michigan.gov/whitmer/0,9309,7-387-90499_90704-540278--,00.html.

[16] The PRMR is the required capacity that a MISO utility needs to procure and/or own, it is calculated by taking the projected peak demand and adding a "reserve margin," which is a buffer of additional capacity to provide system reliability.

transportation electrification, demand-side measures, and distributed generation.[17] In its modeling, the Company used multiple natural gas price forecasts, including its own forecast ("CE gas") and the Energy Information Administration (EIA) 2020 Annual Energy Outlook ("AEO gas").[18] The AEO gas price, ET and EP scenarios are required by the Commission for the IRP.[19]

Using the Aurora software, the Company performed both capacity expansion and production cost modeling but later constructed its portfolios manually. Capacity expansion modeling involves the optimization of the buildout of resources, which can include both selection of new resources and/or retirement of existing resources. This type of modeling chooses the most economic resource additions given the set of assumptions included in the model. This optimization can be circumvented when resources are hard-wired into the model—as I describe later. Production cost modeling holds the resource buildout as fixed and estimates the total costs of owning and operating those resources as well as purchases and sales in the wholesale market. These modeling runs are used as the basis of the net present value (NPV) of a portfolio's cost.

As a hypothetical, the Company ran portfolios where all capacity needs were purchased (assuming 75 percent of the MISO Cost of New Entry or "CONE")—or what the Company described as a "market only" option.[20] Consumers then ran a "supply only" optimization to let Aurora select the supply- or demand-side capacity replacements on an "overnight"

[17] Walz Direct, pp. 7-8.

[18] Walz Direct, pp. 9-10.

[19] Direct Testimony of Anna K. Munie, p. 5.

[20] Walz Direct, pp. 46-47.

basis with no annual constraints on the amount of capacity built in each year.[21] But these runs were not deemed feasible due to constraints on how much of each resource could be built in a given year.[22] The Company constructed "glide path" portfolios that imposed constraints on the annual builds, such as limiting the amount of solar PV built each year to 500 MW (250 ZRCs).[23] These glide paths were manually created by the Company and then run through the production cost model in Aurora. The Company then manually constructed the PCA based in part on "trends observed" in the previous model runs.[24] As the Company states, the final PCA which includes the four-plant gas acquisition is "a glide path portfolio . . . meaning once the resource selection was determined, the resources were locked."[25]

Q. Please summarize the procurement process that the Company conducted that led to the proposed gas acquisition.

A. The Company's decision to procure the four gas plants was predicated on a solicitation for existing gas capacity as a result of its planned unit retirements, and a subsequent analysis conducted by its contractor which recommended that the Company purchase all four plants that bid into this RFP. Consumers decided to seek "existing natural gas fueled generation" claiming that "a significant amount of existing generation capacity would be necessary to accomplish an early retirement" of the Campbell and Karn units.[26] Consumers hired

[21] Walz Direct, pp. 46-47.

[22] Walz Direct, pp. 46-47.

[23] Walz Direct, pp. 47-48.

[24] Ex MEC-16 (MEC-CE-237(a)).

[25] Walz Direct, p. 48.

[26] Revised Direct Testimony of Keith G. Troyer, p. 52.

Charles River Associates (CRA) to conduct the procurement process.[27] In January 2021, CRA issued an RFP for up to 2,000 ZRCs of existing natural gas capacity.[28] By its terms, the RFP was constrained, seeking only gas plants (not other resources), only physical assets (no power purchase agreements), and requiring that the plants be located within Michigan.[29] Only two bidders qualified for participation: 1) New Covert Generating Company who submitted a proposal to sell the Covert plant; and 2) CMS Enterprises, a Consumers affiliate, who submitted proposals to sell the DIG, Kalamazoo, and Livingston plants (and select combinations therein).[30] Ultimately, Consumers chose to buy <u>all</u> of the plants that were bid into the RFP.

CRA calculated an NPV of all four plants that qualified for the RFP by projecting capital costs, operating costs, energy market revenues, ancillary service revenues, and capacity market revenues [[redacted]

---

[27] In discovery, Consumers was asked how it selected the RFP administrator. In its response, the Company stated that "it chose CRA based on several factors, including that CRA had previous experience facilitating Edgar/Allegheny compliant RFPs in which affiliates were permitted to participate." Ex MEC-17 (AG-CE-388(a)).

[28] Troyer Revised Direct, p. 52.

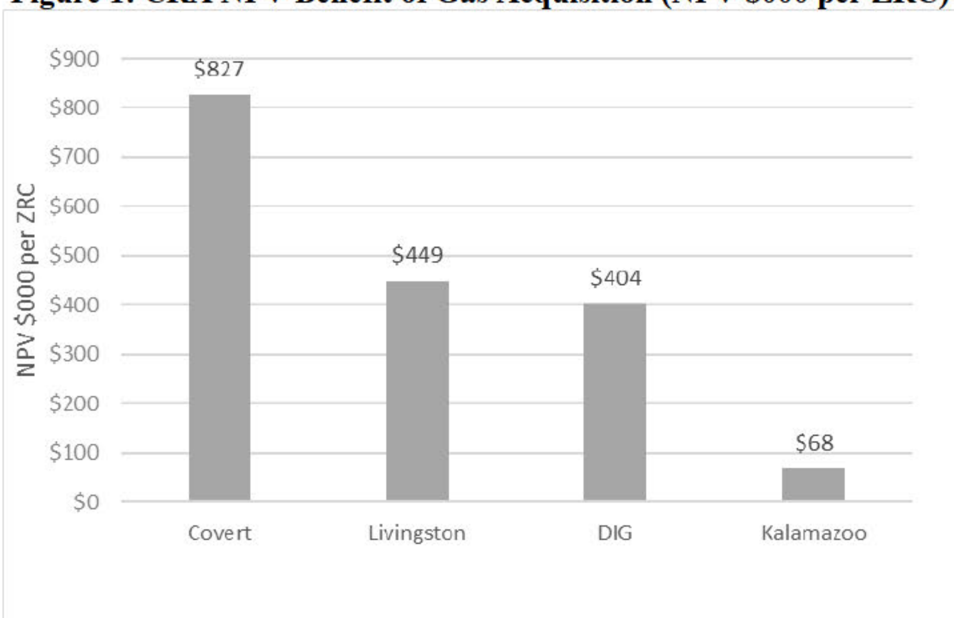
[29] Ex MEC-18, p. 8 (MEC-CE-003, Attachment 3, Request_for_Proposal_Consumers_RFP, p. 5 ("The physical location of such facilities must be in that portion of the lower peninsula of the State of Michigan that is serviced by MISO."); see also *id.*, p. 11.

[30] A copy of CMS's RFP response is attached as confidential Exhibit MEC-19C ("MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 1" sub-folder, CMS Enterprises CE Asset RFP Response).

[31] Ex MEC-20C, p. 2 (MEC-CE-083-CONF (d)(i)). I discuss the Company's capacity value assumptions in Section III of my testimony.

[redacted]]] CRA estimated the NPV (as a net benefit) for the individual plants—shown below in Figure 1. According to CRA's estimates, the Covert plant has by far the highest benefit of the gas plants evaluated, followed by the Livingston plant which is more valuable by itself on a per ZRC basis than when combined with other CMS-owned plants. DIG has the third highest value per ZRC, and Kalamazoo is by far the lowest-valued asset.

Figure 1: CRA NPV Benefit of Gas Acquisition (NPV $000 per ZRC)[34]



[32] The NPV calculations prepared by CRA were produced in discovery. See generally "MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 4" sub-folder, NPV models. Hard copies of the NPV models for DIG and Kalamazoo are attached as Exhibit MEC-21C.

[33] Ex MEC-20C, p. 2 (MEC-CE-083 CONF(d)(iv)). The response states that [[[redacted]]] *Id.*

[34] Ex A-49 (KGT-5), p. 11. The ZRC levels were updated from CRA's based on Consumers' filing (Blumenstock Revised Direct, p. 53). The NPV dollars are directly from CRA's summary results.

During the RFP process, CRA learned of a concern regarding the cost of DIG's natural gas supply.[35] CRA ultimately gave DIG "an asset specific score adjustment due to potential uncertainty around delivered fuel costs related to ongoing rate proceedings for DTE."[36] Consumers clarified in discovery that this was a reference to [[[redacted]]].

CRA's understanding was that Consumers' "resource needs are anticipated to be up to approximately 2,000 MW (UCAP) in aggregate."[38] As a result of that "need" and CRA's own economic analysis, it recommended that the Company consider each of the plants "for more detailed due diligence and review."[39]

Q. Has Consumers completed the due diligence process for these plants?

A. It is unclear. In direct testimony filed on June 30, 2021, Consumers witness Battaglia stated that the "Company performed an extensive due diligence evaluation . . .,"[40] suggesting that

[35] See Ex A-49 (KGT-5), p. 8 ("Dearborn Industrial Generation ("DIG") also received an asset specific score adjustment due to potential uncertainty around delivered fuel costs related to ongoing rate proceedings for DTE."). In a discovery response, the RFP administrator elaborated: [[[redacted]]] Ex MEC-22C (MEC-CE-236 (CONFIDENTIAL)).

[36] Ex A-49, p. 8. In its opinion letter, CRA explained how it accounted for this risk: "Because the magnitude and timing of any adjustment to fuel delivery charges is uncertain at this time, modeling a specific cost increase was considered too speculative to include in the NPV scoring. CRA preferred that the NPV modeling allow for an apples to apples comparison of the economics of the assets. Instead, 25 points were deducted from DIG's score under the asset specific category, which would roughly equate to a 5.0% to 7.5% increase in delivered fuel cost." *Id.*

[37] "MEC-CE-003-Supp-CONF-Attachments" folder, "3h" sub-folder, MEC-CE-003(h).

[38] Ex A-49, p. 8; see also *id.*, p. 2 ("CEC had identified a total need of approximately 2,000 MW on a MISO Unforced Capacity ('UCAP') basis . . . .").

[39] Ex A-49, p. 8.

[40] Direct Testimony of Jeffrey E. Battaglia, p. 38.

this process had concluded. [[[redacted]]]

Q. Please describe how the four gas plants were modeled by Consumers in Aurora.

A. Consumers used CRA's analysis as a basis for selecting the four gas plants, but the Company conducted its own modeling of the four gas plants in Aurora as part of this IRP. However, the four gas plants were only modeled collectively—that is, the Company only performed model runs that included all four gas plants or none of them. Additionally, the four plants were manually included in the Company's modeling runs, rather than being available for the model based on the economics of the individual plants.

When the four plants were locked in, the production cost runs modeled the gas plant units separately using the model's own assumptions, including separate costs for fixed operations and maintenance (FOM), variable operations and maintenance (VOM), and fuel costs. [[[redacted]]] Although Consumers separately modeled the generation and dispatch

---

[41] Ex MEC-23C, p. 1 (MEC-CE-472-CONF (a)).

[42] [[[redacted]]] The Company was able to take this shortcut because it treated all three plants as a single resource.

of the CMS gas units, the Company treated the three CMS plants as a single capacity resource.[43]

Q. Did the Company test other options besides the gas acquisition for replacing the capacity from the retirement of Campbell and Karn?

A. Not as part of this filing. The Company conducted market and supply-side optimization runs using generic market purchases and replacement units, respectively. The Company adjusted its base capacity outlook to include the retirement of Campbell 1-3 in 2025 and Karn 3 and 4 in 2023.[44] But in all portfolios modeled in the IRP where Campbell and Karn are retired in 2025 and 2023, respectively, the four gas plants are <u>always</u> included in that portfolio.[45] The Company also constructed an "Alternate Plan" which assumes continued operation of the Campbell and Karn units as a comparison portfolio that excluded the entire acquisition. The Company's IRP modeling treated the Campbell/Karn retirements and gas acquisition as inextricably linked. Indeed, the Company's testimony also treats them this way: the mid-2020s retirement of the Campbell and Karn units is "conditioned on" the approval of the gas acquisition (as well as the Company getting full recovery of the remaining book balance of the retiring units).[46]

Subsequent to the filing of this case, and after several discovery requests about the Company's modeling approach, Consumers attempted to shore up its decision to manually

---

[43] Ex MEC-24, p. 2 (MEC-CE-046(a)) ("No model runs were performed for the 2021 IRP that assumed acquisition of a smaller <u>subset</u> of Dearborn, Kalamazoo and Livingston."); Ex MEC-25, p. 6 (ST-CE-400(b)) ("[T]he Dearborn, Kalamazoo and Livingston units were required to be selected as a bundle.").

[44] Walz Direct, p. 22.

[45] Ex MEC-24, p. 1 (MEC-CE-040). See also Walz workpaper WP-STW-2 (Glide Path Rainbow Chart Compiler v2 (Not Printed)).

[46] Blumenstock Revised Direct, p. 89.

force Covert and the CMS plants into the model. On October 12, 2021, Consumers revealed that it recently conducted an "exercise" in which, the Company claims, the Aurora model "economically selected" the four gas plants. But in that run the three CMS plants were still bundled together as one package.[47] This exercise—conducted a month ago—does not justify acquiring the three plants if they were taken all together or none at all. As I discuss further in my testimony, the Company's decision-making process that led to the proposed gas acquisition remains flawed. I also discuss concerns with cost and risks at Kalamazoo and DIG that were not addressed by Consumers' modeling.

In another recent discovery response, Consumers also attempted to justify the gas acquisition by citing a "benchmark analysis" that compared Covert and the CMS bids to new gas builds and by providing a diagnostic report that purports to show these gas plants as a cost-effective resource.[48] Again, this does not justify the gas acquisition. Among other things, the Company's IRP modeling used outdated cost assumptions for other resource options, and as noted, the Company failed to evaluate a portfolio that omitted DIG and/or Kalamazoo. In Section VI below, I present portfolios that exclude these two plants and are lower-cost and lower-risk—some of which include capacity purchases, which Consumers neglected to consider at all in its PCA.

[47] Ex MEC-25, p. 6 (ST-CE-400). According to Consumers, this run was conducted on September 28, 2021.

[48] Ex MEC-25, pp. 2-4 (AG-CE-368).

III. CONSUMERS' ASSUMED CAPACITY VALUE IS INFLATED.

Q. Does Consumers overstate the value of capacity in its modeling?

A. Yes. The Company assumes a capacity value of 75 percent of the MISO Cost of New Entry (CONE) as its base assumption.[49] The Company values any capacity surplus or purchases at this value—which effectively means that the Company assumes it would sell or buy capacity at this value. This high capacity value incentivizes the overbuilding of capacity in the IRP. The Company does report the portfolios' costs at varying levels of capacity (0, 25, 50, 75 and 100 percent of CONE), but it still maintains that the 75 percent of CONE is the key value.[50]

As I describe below, there are several problems with the Company's capacity value assumption: First, the MISO capacity price is not the same as the capacity value; second, even if you conflated the two, the MISO price has only been at a small percentage of CONE in almost every past Planning Reserve Auction (PRA); third, [[[redacted]]]; and fourth, [[[redacted]]]. This final point not only shows that Consumers overestimated capacity value generally; it also indicates that Consumers [[[redacted]]] buying the plant outright.

[49] Blumenstock Revised Direct, p. 66.

[50] *Id.*

Q. Please explain the concept of capacity value.

A. In the MISO capacity auctions, the amount of capacity provided by a resource is expressed in zonal resource credits ("ZRCs"), which accounts for forced or random outages at the resource. (This is also called unforced capacity, or "UCAP.") The value of this capacity is separate from a resource's energy value, and there are several ways to measure it.

Below, I describe several concepts related to capacity value, including: the MISO capacity auction clearing price, Consumers' assumption that the future capacity value is 75 percent of CONE, and the cost of capacity through a [[[redacted]]].

Q. Please describe the MISO Planning Reserve Auction (PRA).

A. The MISO PRA is a capacity auction held once a year for the following planning year. Planning years run from June 1st through May 31st. For instance, the most recent auction results reported in April 2021 cover the 2021/2022 planning year (June 1, 2021, through May 31, 2022). The auction covers 10 zones in the MISO region.[51] MISO assigns each zone a local clearing requirement ("LCR") based on expected peak load in a given zone, a reserve margin, and the extent to which that zone can import capacity. The LCR represents MISO's projection of the amount capacity needed within that zone.

Most utilities in MISO either provide their own capacity needs by submitting a fixed resource adequacy plan ("FRAP") or self-schedule their capacity by bidding zero into the auction. Only a small percentage of the capacity cleared in the auction is newly procured by utilities.[52] The maximum potential clearing price in the MISO auction is the cost of new

[51] Both Consumers' and DTE's service territories are in MISO Zone 7.

[52] In recent years, only between 4.7% and 3.6% of cleared capacity in the Planning Resource Action was not part of a FRAP or self-scheduled. See Ex MEC-26, p. 8 (2021/2022 Planning Resource Auction (PRA)

entry (CONE) value, which is based on the annual cost of building and operating a new gas-fired combustion turbine.

Q. Has the clearing price in Zone 7 been low in most years?

A. Yes. The clearing prices in Zone 7 for the past several years are shown below in Table 1. This shows that the clearing prices have been volatile, but Zone 7 (like other MISO zones) typically cleared at a small percentage of CONE. The 2020/21 result was a clear outlier compared to most auction results. The latest auction result of $5/MW-day, or 2 percent of CONE, is more the "norm."

Table 1: MISO Planning Resource Auction Zone 7 Clearing Prices ($/MW-day)[53]

MISO Planning Year	Zone 7 clearing price ($/MW-day)	% of CONE
2014/15	$16.75	7%
2015/16	$3.48	1%
2016/17	$72.00	28%
2017/18	$1.50	1%
2018/19	$10.00	4%
2019/20	$24.30	10%
2020/21	$257.30	100%
2021/22	$5.00	2%

Results (Apr. 15, 2021), slide 8), available at: https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf..

[53] Ex MEC-26, pp. 5, 8 (2021/2022 PRA Results, slides 5 and 9); *id.*, p. 19 (U20963-MEC-CE-017-Hugo_ATT_1).

Q. Is it appropriate to rely solely on the MISO capacity price to assess the value of capacity?

A. No. The MISO capacity market (i.e., Planning Resource Auction) clearing price is a limited indicator of capacity value. It shows whether a zone has a shortage or surplus in capacity; however, this cannot be used as the definitive value of capacity because, typically, MISO utilities provide most or all of their own capacity needs. The PRA is a voluntary balance market, whereby utilities can sell excess capacity (i.e., above their MISO reserve requirement) or purchase a small amount as needed (i.e., to meet their MISO reserve requirement). For a vertically integrated utility like Consumers, the clearing price of this market only matters to the net amount of capacity sold or purchased by the utility through the PRA. If, for instance, a utility had exactly the amount of capacity required by MISO, then the PRA clearing price in that zone would not affect the utility.[54]

Q. Has Consumers assumed the 75 percent CONE capacity value in the past?

A. Yes. This is the same capacity value assumption that Consumers presented in its 2021 rate case, 2020 rate case, and 2018 IRP case. In the 2020 rate case (U-20697), the Company suggested that its capacity value assumption was tied to the PRA results. More specifically, the Company stated that it projected this 75 percent value "based on the premise that if Zone 7 was short on capacity, the capacity prices would hit CONE for 3 years and by year

[54] Consumers agreed with this premise in the 2018 IRP case. See Case No. U-20165, Clark Direct, 7 TR 952 (testifying that "the results of the MISO PRA do not represent reliable capacity values to replace [Campbell units 1 and 2 and Karn units 1 and 2]. The MISO PRA is a residual market and does not represent a permanent supply that can be relied on to meet customer demands. The MISO PRA is a market designed to enable the monetization of excess capacity created by the uncertainty of load growth and the historically lumpy nature in which capacity additions occur in the utility industry.")..

4 a new resource would be available."[55] But this does not comport with the market results, where the typical clearing price has been low.

Q. Even if the MISO auction price were a useful value for capacity, is it reasonable to assume that Zone 7 will clear at such a high price?

A. No. MISO has conducted a Planning Resource Auction annually since 2013, and there was a high clearing price for MISO Zone 7 in only one of those auctions: in the last year's auction (for the 2020/21 planning year) the clearing price for MISO 7 was CONE. The clearing price in the April 2021 auction (for the 2021/21 planning year) – $5 per MW-day, 2 percent of CONE – is more of a typical result.

[[[redacted]]] Consumers' 75 percent CONE assumption—shown below in Figure 2. [[[redacted]]]

[55] Ex MEC-27 (Case No. U-20697, discovery response U20697-MEC-CE-033(c)).

[56] Ex MEC-20C, p. 2 (MEC-CE-083-CONF (d)(i)).

Figure 2: Capacity Price Comparison, MISO Zone 7 ($/MW-day, Planning Year)[57] [[CONFIDENTIAL

[redacted]

Q. Are bilateral contracts for capacity an indicator of capacity value?

A. Yes. The MISO PRA prices are extreme (as shown above): zonal prices can be near the floor if the zone is slightly over capacity or, as occurred on only one occasion, reach maximum price of CONE if there is a slight shortage. If one relied solely on PRA prices as a measure of value, one would conclude that all of the capacity in a zone is either worth close to nothing or the highest possible value, depending on the year. A bilateral contract is a better indicator of the value of capacity because both the buyer and seller have to agree upon a value.

Q. Did Consumers recently inform parties that [[[redacted]]]?

[57] Exhibit A-3 (RTB-3), p. 25; see also "MEC-CE-003-Supp-CONF-Attachments" folder, "3g" sub-folder, "(iii)" sub-folder, Consumers_Base_Results_02_10_21. Values from sources were all translated into $/MW-day.

A. Yes. [[[redacted]]] This shows yet another example of how the Company is over-valuing capacity; in this case it [[[redacted]]]. Moreover, if Consumers did not [[[redacted]]]

58 Ex MEC-28C, p. 2 (MEC-CE-060-CONF (d)).

59 Ex MEC-28C, p. 3 (U21090-MEC-CE-060-CONF-Walz_CONF_ATT_2).

Figure 3: Capacity Price Comparison and [[[redacted]]], MISO Zone 7 ($/MW-day, Planning Year)[60] [[CONFIDENTIAL

[redacted]

A. There is overwhelming evidence that the 75 perent CONE used by Consumers is too high. Most importantly, [[[redacted]]]. Further, in my testimony where I present modeling results, while I still show the 75 percent CONE value, I place more stock in the 50 percent CONE results—as should the Commission.

[60] Exhibit A-3 (RTB-3), p. 25; “MEC-CE-003-Supp-CONF-Attachments” folder, “3g” sub-folder, “(iii)” sub-folder, Consumers_Base_Results_02_10_21. Values from sources were all translated into $/MW-day.

IV. CONSUMERS' GAS PLANT ACQUISITION DECISION LACKED COMPETITION AND RIGOR.

Q. Please summarize this section of your testimony.

A. In this section, I examine the Company's decision to pursue the four gas plants. There are several critical flaws in the Company's proposal that, at a bare minimum, cast doubt on whether the Commission should approve this acquisition without modification. The Company is pursuing a massive transformation of its energy system by adding roughly 2 GW of natural gas to its resource mix. A decision of this magnitude requires more consideration and support than what the Company has provided in this case.

First and foremost, the Company did not consider other resource options for replacing the retiring Campbell and Karn capacity apart from existing gas capacity. Second, instead of soliciting a larger sample of competitive resource options, the Company solicited only existing gas units located in MISO Zone 7[61] and, lacking any other options, moved forward with the two proposals (including the four plants) that were approved for participation. Further, the analysis that CRA conducted for Consumers [[[redacted]]] Third, the Company only modeled the gas acquisition as one whole in its IRP modeling rather than examine whether a subset or none of the plants could achieve the Company's goals at lower cost or risks to customers. Fourth, the Company used outdated renewable and battery storage costs in its Aurora modeling. Specifically, it used forecasts from 2019 when 2020 data was available about a year prior to the filing.

[61] Ex A-49, p. 2 ("The physical location of such facilities was required to be in the portion of the lower peninsula of the State of Michigan that is serviced by MISO and/or be capable of being classified as MISO local resource zone 7 ('LRZ7') capacity."). Covert currently operates in the PJM market, but the plant is physically located in Zone 7, and Company witness Blumenstock testified that the plant would transfer to MISO if purchased by Consumers. Blumenstock Revised Direct, pp. 54-55.

A. Consumers' solicitation design stifled competition and restricted the qualified bids to the four gas plants

Q. Did the Company's RFP garner many resource options for it to pursue?

A. No, the Company's solicitation specifications led to limited options. As I described above, the Company's RFP was for existing gas generation of up to 2,000 MW capacity located in MISO Zone 7.[62] As a result of these limited specifications, the only qualified bids were the four gas plants that Consumers ultimately selected—three of which are owned by a Company affiliate.

Q. Should the Company have issued a more competitive solicitation?

A. Yes. The Company should have cast a wider net in terms of the resource replacement types—such as by conducting an all-source RFP. Other utilities have done so as a means of testing the portfolio for replacing retiring coal units. Below are two examples:

First, in its 2017 IRP, PNM (Public Service Company of New Mexico), a New Mexico-based electric utility, found that retirement of the San Juan coal plant (located in Farmington, NM) was cheaper than continuing the plant's operations. After this finding, PNM issued an all-source RFP in October 2017 and a subsequent storage-only RFP in April 2019.[63] The all-source RFP resulted in 345 bids. Out of these bids, PNM constructed a replacement portfolio that included 350 MW of solar, 130 MW of battery storage, and 280 MW of natural gas.[64] But instead of adopting PNM's portfolio, the Commission

[62] Ex A-49, p. 2.

[63] N.M. Public Reg. Comm'n, Docket No. 19-00195-UT, Direct Testimony of Roger W. Nagel, p. 13, (July 1, 2019), available at https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1179834.

[64] N.M. Public Reg. Comm'n, Docket No. 19-00195-UT, Direct Testimony of Roger W. Nagel, pp. 6-7.

approved the "CCAE 1" portfolio—which I and others developed in testimony in that case—and which ultimately included 650 MW of solar, 300 MW of battery storage, and no new gas generation.[65]

Second, Xcel Colorado solicited all resource types in 2017. Xcel's modeling showed that retiring two coal units early, Comanche 1 and 2 in 2022 and 2025 (respectively), and replacing them with mostly wind, solar, and gas combustion turbines was lower-cost than continuing the coal units' operations and replacing them later.[66] The utility received 430 bids, over 350 of which were for renewable energy or storage.[67] The utility ultimately chose a portfolio that included early retirement of the two coal units, and the addition of 1,131 MW of wind, 707 MW of solar, 275 MW of battery and 383 MW of gas.[68]

Both PNM and Xcel Colorado sought a competitive, robust sample of bids and both ultimately advocated for early coal retirement combined with mostly renewable and storage replacement resources. By contrast, Consumers determined prior to issuing the RFP that all 2,000 MWs of capacity would be filled by natural gas capacity and tailored its RFP accordingly, which resulted in a very limited array of bidders from which Consumers could

---

[65] N.M. Public Reg. Comm'n, Docket No. 19-00195-UT, Order on Recommended Decision on Replacement Resources – Part II at 15, (July 29, 2020), *available at* https://edocket.nmprc.state.nm.us/AspSoft/HandlerDocument.ashx?document_id=1191982

[66] Colo. Public Utility Comm'n, Docket No. 16A-0396E, Rebuttal Testimony and Attachments of James F. Hill, p. 38, Table JFH-12, (Jan. 29, 2018).

[67] Colo. Public Utility Comm'n, Docket No. 16A-0396E, Xcel Energy Colorado, 2017 All Source Solicitation: 30-Day Report, p. 3, (Dec. 28, 2017), *available at* https://assets.documentcloud.org/documents/4340162/Xcel-Solicitation-Report.pdf.

[68] Colo. Public Utility Comm'n, Docket No. 16A-0396E, Xcel Energy Colorado, Electric Resource Plan: 120-Day Report, p. 15, (June 6, 2018), *available at* https://www.powermag.com/wp-content/uploads/2018/06/xcel-2018-clean-energy-plan.pdf.

choose. Tellingly, while other utilities have fielded hundreds of resource options by seeking a competitive, less restrictive sample, Consumers received only four resource options and pursued all of them.

Q. Should there be a concern that three of the four plants are owned by the Company's affiliate, CMS Enterprises?

A. Yes. The Company will have to apply for approval of an inter-affiliate transaction from FERC if it wants to purchase the DIG, Kalamazoo, or Livingston plants (or any combination of therein). FERC will review this affiliate pursuant to Section 203 of the Federal Power Act. The Section 203 process is intended to prevent unfair, anti-competitive practices because "[a]cquisitions involving affiliates have an inherent potential for discriminatory treatment in favor of the affiliate" and "[a]ffiliate preference when acquiring assets can have serious adverse effects on competition and may therefore not be consistent with the public interest."[69] As Company witness Troyer notes, one of the ways in which a utility can demonstrate to FERC that its proposed transaction does not inappropriately favor an affiliate is through a competitive solicitation.[70] The Company appears confident that it will get FERC's approval, largely as a result of the Company's RFP.[71] But, there are shortcomings inherent in the Company's solicitation process that could potentially cause FERC to deny Consumers' Section 203 application because FERC will be unable to "assure that [Consumers'] acquisition of a plant from an affiliate is free from preferential

[69] *Ameren Energy Generating Co.*, 108 FERC ¶ 61081, 61410 (2004).

[70] Troyer Revised Direct, p. 57.

[71] Troyer Revised Direct, pp. 55-60.

treatment."[72] FERC evaluates competitive solicitations for Section 203 application purposes using the four guidelines in *Allegheny Energy Generating Co.* – transparency, definition, evaluation, and oversight.[73] Mr. Troyer briefly describes how the Company believes it has satisfied each of these guidelines, but significant issues remain.

Q. Is there likely to be scrutiny of how well the solicitation encouraged competitiveness?

A. Yes. "Transparency" in the solicitation requires that "the competitive solicitation process should be open and fair."[74] FERC has previously stated that "an RFP should not be written to exclude products that can appropriately fill the issuing company's objectives. This is particularly important if such exclusions tend to favor affiliates."[75] But Consumers' solicitation was so specific that it could be construed as directly targeting the CMS plants—after all, they represented three of the four qualified bids.

The "definition" guideline requires that the "the product or products sought through the competitive solicitation should be precisely defined."[76] But "precisely defined" does not mean that the RFP's definition should omit reasonable resource options. For instance, several years ago I testified before the West Virginia Public Service Commission (WVPSC) in a case involving a regulated utility that sought to purchase the Pleasants coal plant from its unregulated affiliate—analogous to Consumers' proposed acquisition of

---

[72] *Ameren*, 108 FERC ¶ 61081, 61410.

[73] *Allegheny Energy Supply Co.*, 108 FERC ¶ 61082 (2004).

[74] *Allegheny*, 108 FERC ¶ 61082, 61417.

[75] *Ameren*, 108 FERC ¶ 61081, 61412.

[76] *Allegheny*, 108 FERC ¶ 61082, 61417.

CMS assets in this case. In that case, as in this one, the utility proposed acquiring an affiliate-owned power plant following an RFP (also administered by CRA). In that WVPSC case, I criticized the RFP for being overly specific and tailored towards one outcome, namely the purchase of the Pleasants plant.[77] The RFP in that case requested 1,300 MW of capacity, and specified that (i) the utility sought the 100% ownership of dispatchable capacity, and (ii) the capacity should be located in the utility's transmission zone (APS in PJM).[78] In a separate FERC docket (which I was not involved in), FERC rejected the acquisition of the plant in part because of the overly narrow definition of the need.[79] Because the RFP was too specific, FERC found that the Pleasants transaction did not meet the "definition" standard, concluding that the "the product sought was overly narrow because the stated objective could have been achieved if the RFP considered PPAs and resources that were outside of the APS zone."[80]

The Company claims that there were more plants that "*could have* participated,"[81] but potential bidders could have not considered it worth bidding if they thought that the RFP was seeking specific plants.

[77]Exhibit MEC-29, pp. 4-5, West Virginia Public Service Commission, Case No. 17-0296-E-PC, Direct Testimony of Tyler Comings, pp. 38-39. Available at: http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=480180&NotType=%27WebDocket%27.

[78] WVPSC, Case No. 17-0296-E-PC, Comings Direct Testimony, p. 38.

[79] *Monongahela Power Co. Allegheny Energy Supply Co., LLC*, 162 FERC ¶ 61015 (2018). The RFP's identified capacity need was very close to the capacity of the Pleasants plant (1,159 MW), which was also located in the desired PJM zone. *Id.*

[80] *Monongahela Power Co.*, 162 FERC ¶ 61015, p. 32.

[81] ST-CE-404 (emphasis in original).

Q. Is there likely to be scrutiny of how the bidding process was overseen?

A. Yes. The "oversight" guideline requires that "an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection."[82] Consumers hired CRA to fulfill this role, but it appears that Consumers maintained close involvement in the process. In the letter from CRA to Consumers, CRA states that "CRA and CEC mutually identified existing assets within LRZ7 [MISO ZONE 7] that appeared to meet the minimum requirements for participation in the RFP."[83] CRA also stated that Consumers was not aware of any of the bidders' identities during the RFP FAQ process,[84] [[[redacted]]][85] For Consumers to show FERC that the purchase of the CMS plants abides by all of the guidelines for inter-affiliate purchases will not be an open and shut case. It is at best questionable whether the transaction will pass muster under FERC standards.

B. CRA's evaluation of the four plants should not have been used to justify the acquisition

Q. Did CRA provide an analysis of the costs to customers, or revenue requirements?

A. [[[redacted]

[82] *Allegheny*, 108 FERC 61082, 61417.

[83] Ex A-49, p. 2.

[84] Ex. A-49, p. 6.

[85] Ex MEC-30C ("MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 2" sub-folder, pre-qual)

[86] Ex MEC-20C, p. 1 (MEC-CE-083-CONF (a)).

[redacted]]]

Q. Did CRA analysis model the plants operating past 2040?

A. [[[redacted]]]

87 Ex MEC-20C, p. 2 (MEC-CE-083-CONF (b)(ii)).

88 Ex MEC-20C, p. 2 (MEC-CE-083-CONF (c)). [[redacted]] See generally Ex MEC-31C (MEC-CE-482, U21090-MEC-CE-482 Att5 Covert Plant Modeling RFP fixed costs CONFIDENTIAL; U21090-MEC-CE-482 Att6 Dearborn_Kzoo_Liv Plants Modeling RFP fixed costs CONFIDENTIAL); see also Ex MEC-32C (MEC-CE-239 (Conf.))

89 MEC-CE-83(c) asks [[[redacted]]

C. The Company's IRP should not treat the gas plants as an all or nothing proposition

Q. Did Consumers test the value of the individual plants or subsets of them for its IRP?

A. No. Consumers treated the four plants as an all or none deal—either taken all together or none at all.[90] The Company justified its decision to pursue these plants based on CRA's analysis, but that analysis shows a wide range of relative values amongst the four gas plants. CRA also produced individual valuations of the plants and CMS offered Livingston and Kalamazoo plants individually as well as a combination of those two plants (i.e., excluding DIG).[91] Consumers could have at least tested modeling a subset of the acquisition in its IRP modeling but it did not. Similarly, although CMS submitted proposals for different combinations of Livingston, Kalamazoo, and DIG,[92] the Company treated the three CMS plants as a single, bundled resource in its IRP modeling by failing to evaluate any model runs with a subset of those plants.[93] As a result, one can only see portfolios with or without the entire gas acquisition, which is a limited framework that prevents the exploration of individual or subsets of the plants. The Company attempted to justify the acquisition after the filing in a run that the Company did just a month ago. But even this this updated modeling still lumped the CMS plants together as one package deal.[94]

[90] Ex MEC-24, p. 1 (MEC-CE-040) ("All Consumers Energy Aurora cases in which Karn units 3 and 4 are retired in 2023, and Campbell units 1, 2 and 3 are retired in 2025 include the manual addition of Covert, Dearborn, Kalamazoo and Livingston.")

[91] Ex A-49, p. 5.

[92] *Id.*

[93] Ex MEC-24, p. 2 (MEC-CE-046(a)).

[94] Ex MEC-25, p. 6 (MEC-CE-400(b)).

Q. Did Consumers pursue short-term capacity purchases as an alternative to the acquisition?

A. No. The Company was aware of contracted capacity purchases at the DIG plant, [[[redacted]]]. The Company could have taken a more incremental approach by buying contracted capacity as-needed and then leaving its options open for future resource procurement. Instead, it opted to lock in 2 GW of gas until 2040 and foreclose alternatives to that massive acquisition.

Q. Did you find savings with pursuing other avenues outside of the entire gas acquisition?

A. Yes. As I describe later in my testimony, we used more up-to-date resource cost assumptions and found lower-cost portfolios that included a subset of the acquisition (two of the four plants) and either capacity purchases or new battery storage builds in order to satisfy capacity needs.

D. The Company used outdated renewable and storage cost data.

Q. What was the source for Consumers' renewable costs?

A. Consumers used the National Renewable Energy Laboratory's (NREL) 2019 Annual Technology Baseline—or NREL ATB 2019—as the primary source for the costs of wind, solar PV, and battery storage.[95] Since the ATB 2019, NREL has released two annual updates to this data.[96] Consumers made adjustments to its primary data from ATB 2019 to

[95] Battaglia Direct, pp. 8, 21.

[96] See: https://atb.nrel.gov/electricity/2021/data (NREL ATB 2021) and https://atb-archive.nrel.gov/electricity/2020/data.php (NREL ATB 2020), last checked October 14, 2021.

adjust for what it believed would be lower future costs. However, the Company could have at least used the ATB 2020 instead, which was available in July of 2020.[97] I do not expect the Company to have used the ATB 2021, but Consumers had ample time to use the ATB 2020 data.

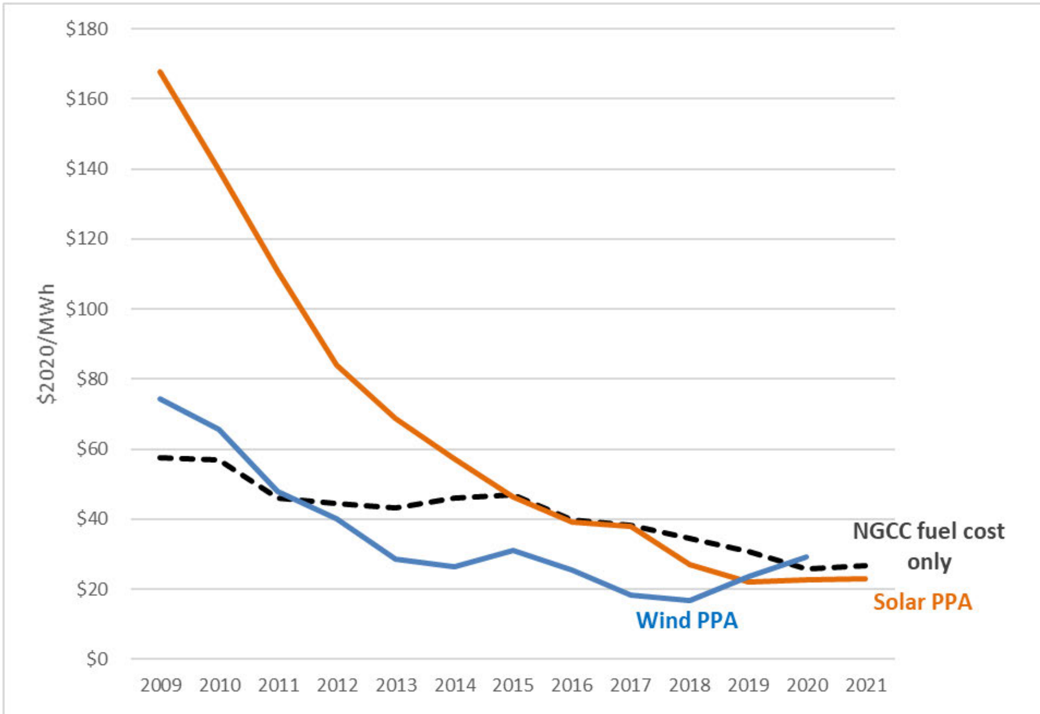
Forecasts of renewable and storage costs change often, but two-year old data is already out of date. Recent trends in renewable and storage costs show sharp declines in the past decade—especially for solar PV and battery. For example, a survey of actual project costs from Lawrence Berkeley National Laboratory (LBNL) shows that the all-in costs of solar PV and wind PPAs are at or below the fuel costs of natural gas combined cycle units (see Figure 42). NREL also reports that battery prices decreased by 87 percent between 2010 and 2019.[98]

---

[97] See: https://www.nrel.gov/news/program/2020/2020-annual-technology-baseline-electricity-data-now-available.html, last checked October 14, 2021.

[98] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis. *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmark: Q1 2020*, National Renewable Energy Laboratory (NREL), *available at* https://www.nrel.gov/docs/fy21osti/78882.pdf, p. 25, last checked October 14, 2021.

Figure 4: LBNL Levelized Solar PV, Wind and Natural Gas Combined Cycle Fuel Costs ($2020/MWh)[99]



Q. Did Consumers account for the most recent extensions of federal tax credits in December of 2020?

A. Not all of them. The Investment Tax Credit (ITC) and Production Tax Credit (PTC) were both extended by Congress in December of 2020. Consumers accounted for the ITC extension, which is applied to the capital costs of solar and solar-battery hybrids; but it did not account for the extension of the PTC which would apply to wind projects installed by 2025.[100] This means that not only is the source for Consumers' renewable costs outdated,

---

[99] Bolinger, Mark, Joachim Seel, Cody Warner, and Dana Robson, *Utility-Scale Solar*, *2021 Edition*, Lawrence Berkeley National Laboratory (LBNL) (October 2021), *available at* https://emp.lbl.gov/utility-scale-solar/ (recreated from Excel data provided by the authors), last checked on October 14, 2021.

[100] Ex MEC-33 (MEC-CE-066(a)).

they are further inflated for wind resources in 2025 by not incorporating tax credit extensions from last year.

Q. Has Consumers justified pursuing the gas acquisition?

A. No. In summary, Consumers has taken a myopic and uncritical approach to its proposed acquisition of Covert, DIG, Kalamazoo, and Livingston. At the start, Consumers issued an RFP which only sought specific characteristics that these four plants met—rather than seeking a large, competitive sample of resources from which to choose. The Company based its decision to pursue the four plants on CRA's analysis, which that contractor [[redacted]]. The Company's own modeling in Aurora treated the acquisition as an all or none deal, failing to consider individual plants or a subset of the four plants. Consumers also did not use up-to-date costs for other resource options in its modeling, including failing to update all of the latest tax credits available. Moreover, as discussed in Section III, Company continues to overvalue capacity—including when compared to forecasts [[redacted]]. In the next section, I discuss risks that are specific to the DIG and Kalamazoo plants. Subsequently, I present alternative portfolios that exclude these two plants.

V. THE RISKS OF PURSUING DIG AND KALAMAZOO

Q. Do you have concerns that are specific to the Company pursuing DIG and Kalamazoo?

A. Yes. In this section, I highlight the risks to Consumers and its ratepayers of pursuing the DIG and Kalamazoo plants which raise additional concerns over and above those I have addressed on the Company's general approach to the acquisition of the four plants. For DIG, in particular, I am concerned with the plant's vulnerability to carbon emissions regulation and the potential for costly [[[redacted]]] Generally, there are also higher risks of pursuing DIG and Kalamazoo due to the plants' [[[redacted]]]. For Kalamazoo, in particular, the historical capital costs are [[[redacted]]]

Q. Consumers largely ignored any carbon dioxide compliance costs, is that reasonable to assume through 2040?

A. No. The Company did not model a cost of carbon when developing its portfolios; it merely tested a carbon price as a "risk variable" after the portfolios were created.[101] The explanation for this omission is that there is no known value to use, but this does not preclude other utilities and [[[redacted]]]] from modeling a carbon price. Making long-term resource decisions about carbon-emitting resources should require addressing the associated costs of those emissions at the outset of modeling—not after the resource choice has already been made. In my experience, it has recently become common practice to model a carbon price optimization and/or portfolio cost in order to capture the risks of carbon regulations or a utility's own carbon goal; in many cases the utility includes a carbon cost in the base case.[102]

---

[101] Munie Direct, p. 21.

[102] See: Entergy 2021 IRP Modeling Results, slides 11-14 (available at: https://cdn.entergy-arkansas.com/userfiles/content/IRP/2021/EAL_IRP_Stakeholder_Modeling_Materials.pdf); Ameren 2021 IRP Update, p. 47, (available at: https://www.ameren.com/-/media/missouri-site/files/environment/irp/2021/irp-update.pdf?la=en-us-mo&hash=7B7D3DFEEC953E86FECC28CE631F5B6F7FB34CF0);

Q. Did CRA's analysis reveal that DIG was particularly sensitive to any [[[redacted]]]?

A. CRA's analysis demonstrates that DIG is [[[redacted]]]

[103] The NPV models for all four plants were provided in discovery. See "MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 4" sub-folder, NPV models for all plants.

Figure 5: Comparison of Capacity Factors for DIG CONFIDENTIAL[104]

[redacted]

Q. Are there additional [[[redacted]]] risks at DIG?

A. Yes, there is a potential that the plant will [[[redacted]

[104] "MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 4" sub-folder, NPV Model- Dearborn; Aurora outputs provided by Consumers for "240_12_01_BAUCE_PCA_Final" and "108_12_01_BAUAEO_PX_Base_PCA_Glide_Path."

[105] Ex MEC-2C, p. 2 (MEC-CE-088 (Revised); "MEC-CE-088_ATTS_1 CONFIDENTIAL" folder, "DIG" sub-folder, [[[redacted]]])

[106] Ex MEC-2C, p. 2 (MEC-CE-088 (Revised); "MEC-CE-088_ATTS_1 CONFIDENTIAL" folder, "DIG" sub-folder, [[[redacted]]])

[107] Ex MEC-6C, pp. 1-2 ("MEC-CE-088_ATTS_1 CONFIDENTIAL" folder, "DIG" sub-folder, [[[redacted]]]).

[redacted]]] These issues are discussed in more detail by MNS witness Douglas Jester.

Q. Did CRA's analysis show the relatively [[redacted]] costs of DIG and Kalamazoo?

A. Yes. I have previously stated reasons why the CRA analysis alone cannot be used to [[redacted]]] However, the relative value of the plants from CRA's analysis is instructive: (in descending order and on a per ZRC basis) Covert, Livingston, DIG, and Kalamazoo (see Figure 1). The relatively low value of the DIG and Kalamazoo plants is driven by their [[redacted]]. The annual fixed costs (capital expenditures and fixed O&M) of DIG and Kalamazoo are [[redacted]] that of Livingston and Covert on a per kW-year basis in

[108] Ex MEC-2C, p. 2 ("MEC-CE-088_ATTS_1 CONFIDENTIAL" folder, "DIG" sub-folder, [[redacted]]).

[109] Ex MEC-3C, pp. 6-7, 12 ("MEC-CE-088_ATTS_1 CONFIDENTIAL" folder, "DIG" sub-folder, [[redacted]).

[110] See Ex MEC-9C (MEC-CE-473-CONF).

CRA's analysis as shown in Figure 6; these also form the basis for Consumers' modeling of the plants.[111] These much [[[redacted]]] make DIG and Kalamazoo substantially less attractive to pursue than Covert and Livingston. In fact, [[[redacted]]].[112]

Figure 6: CRA's Projected Annual Fixed Costs ($/kW-year) CONFIDENTIAL[113] [[

[redacted]

Q. Are the capital expenditures (capex) shown above for Kalamazoo likely understated?

A. Yes. The historical capital expenditures for Kalamazoo are [[[redacted]]] Figure 7 below. In 2019, the plant had $7 million in capital

---

[111] See generally Ex MEC-31C (U21090-MEC-CE-482 Att5 Covert Plant Modeling RFP fixed costs CONFIDENTIAL; U21090-MEC-CE-482 Att6 Dearborn_Kzoo_Liv Plants Modeling RFP fixed costs CONFIDENTIAL).

[112] Ex MEC-34C ("MEC-CE-003-Supp-CONF-Attachments" folder, "3c. Emails" sub-folder, "Other Communications" sub-folder, "CMS" sub-folder, [[redacted]]]

[113] MEC-CE-003 CONF" folder, "CONFIDENTIAL Attachment 4" sub-folder, NPV models for all plants.

costs which decreased to $1.8 million in 2020,[114] but [[[redacted]]] annual costs through 2040. While CRA's [[[redacted]]] annual cost assumption was overly optimistic, Consumers [[[redacted]]].[115]

Figure 7: [[[redacted]]]

[redacted]

Q. Are the risks of owning DIG and Kalamazoo clearly higher than owning Covert and Livingston?

A. Yes, as described above, DIG in particular carries significant uncertainties which leave any owner of the plant vulnerable to potential environmental regulations. Kalamazoo and DIG

---

[114] Ex MEC-35, p. 11 (U21090-MEC-CE-058-Kapala_ATT_2, "Appendix E - KRGS" tab, line 58).

[115] Ex MEC-31C, p. 36 (482-U21090-MEC-CE-482 Att6 Dearborn_Kzoo_Liv Plants Modeling RFP fixed costs CONFIDENTIAL) [[[redacted]]].

both generally carry about [[[redacted]]] the fixed cost per kW than the other two plants, making them a heavier burden. Moreover, the projected costs of Kalamazoo are already [[[redacted]]] in the CRA and Consumers' modeling. These factors, in addition to the relative NPV values developed by CRA, should lead a reasonable resource planner to favor Covert and Livingston over DIG and Kalamazoo.

VI. THE COMPANY SHOULD PURSUE A RESOURCE PLAN THAT OMITS DIG AND KALAMAZOO, WHICH WOULD PROVIDE MORE SAVINGS AND LESS RISK THAN THE PCA

Q. Did you develop alternative portfolios in this case?

A. Yes, along with my co-witness George Evans, we developed alternative portfolio types that we then compared to the costs of the Company's proposed PCA under combinations of the Company's two main gas prices (CE and AEO) and the BAU scenario. We also modeled one of the portfolio types under the Commission-required ET, and EP scenarios.

Both options used the PCA as a jumping off point including assuming the same capacity requirements and constraints. Our portfolios include nearly identical amounts of solar PV and battery by 2040 as the PCA, but they only include the Covert and Livingston plants from the gas acquisition. Instead of the DIG and Kalamazoo capacity, our portfolios either add: 1) capacity purchases when needed; or 2) added battery storage in 2025, 2029 and 2030. As shown below in Figure 8 (for the capacity purchase pathway) and Figure 9 (for the new build pathway), both are less costly than the Company's PCA under 50 percent CONE capacity value or higher in every scenario modeled when taking the average of the Consumers and AEO gas price results. The capacity purchase option and every new build run under the AEO gas price forecast are all cheaper under all capacity values.

Figure 8: Summary of Capacity Purchase Portfolio Savings vs. PCA ($mil NPV)

Capacity Purchases		100% CONE	75% CONE	50% CONE	25% CONE	0% CONE
BAU	AEO Gas	$148	$178	$208	$238	$268
	CE Gas	$17	$43	$68	$93	$119
	BAU Avg	**$83**	**$110**	**$138**	**$166**	**$193**

Figure 9: Summary of New Build Portfolio Savings vs. PCA ($mil NPV)

New Build		100% CONE	75% CONE	50% CONE	25% CONE	0% CONE
BAU	AEO Gas	$247	$228	$209	$190	$170
	CE Gas	($123)	($147)	($172)	($197)	($221)
	BAU Avg	**$62**	**$40**	**$18**	**($4)**	**($25)**
ET	AEO Gas	$479	$459	$440	$421	$402
	CE Gas	$32	$14	($4)	($22)	($40)
	ET Avg	**$255**	**$237**	**$218**	**$199**	**$181**
EP	AEO Gas	$144	$125	$106	$86	$67
	CE Gas	$140	$122	$104	$86	$68
	EP Avg	**$142**	**$124**	**$105**	**$86**	**$68**

A. <u>We made alterations to the Company's PCA and corrected flaws in the input assumptions</u>

Q. Please summarize the similarities and differences between your and Consumers' modeling.

A. We made several alterations to the Company's modeling approach and inputs assumptions; but we also maintained several aspects of the Company's PCA. I recommended that the Company update its renewable and storage cost assumptions to use the NREL ATB 2020, which was released over a year ago but would have been available to the Company in developing this IRP. Mr. Evans also re-modeled the Company's PCA using my updated costs to enable an apples-to-apples comparison of our plans. We retained many of Consumers' constraints on their modeling, including that only 500 MW (250 ZRCs) of solar could be built in one year and maintaining a 200 ZRC excess capacity after 2025 for the new build portfolios.[116] Our recommended plans ultimately include very similar builds of solar PV and battery storage by 2040 as the Company's PCA.

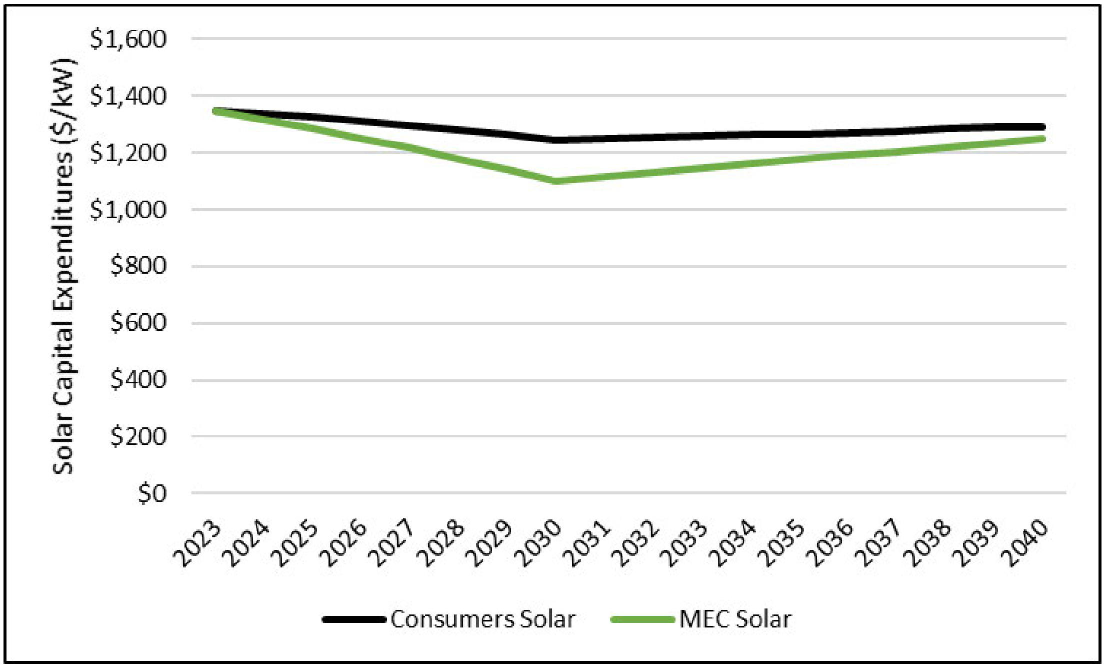
Q. Please provide the alterations you made to the Company's renewable and storage costs.

A. As discussed previously, the Company relied on NREL ATB 2019 as a primary source for its solar, wind, and battery storage costs. The Company took the average of the NREL 2019 base and low costs for solar and battery storage as a way of addressing the downward trend in those forecasts.[117] An update using the NREL ATB 2020 base case prices (shown below in Figures 10-12) lowers the solar PV and wind costs compared to what the Company assumed, slightly raises the battery storage costs, and leaves solar battery hybrid costs similar between the two (the effects of changes in solar and battery costs effectively cancelling out).

[116] The 500 MW solar cap is discussed in detail in the testimony of MNS witness Douglas Jester.

[117] Battaglia Direct, p. 25.

Figure 10: Capital Costs of Solar PV ($/kW nominal)[118]



118 MEC-CE-069-Battaglia_ATT_1, MEC-CE-069-Battaglia_ATT_2, MEC-CE-069-Battaglia_ATT_3; NREL 2020 ATB (https://atb-archive.nrel.gov/electricity/2020/data.php).

Figure 11: Capital Costs of In-State and Out-of-State Wind ($/kW nominal)[119]

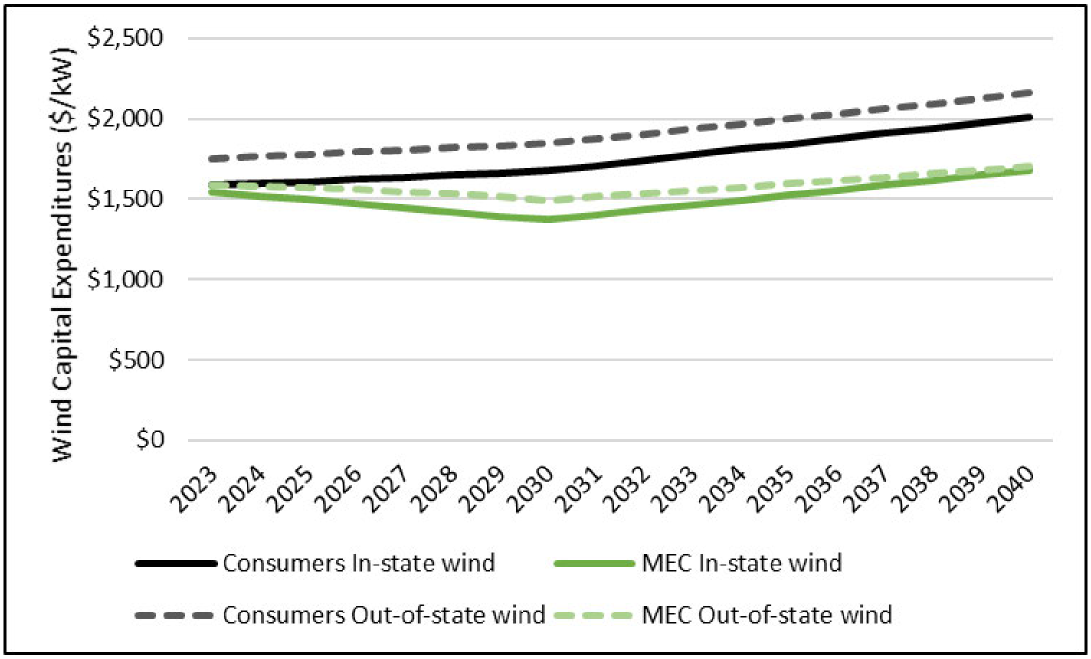
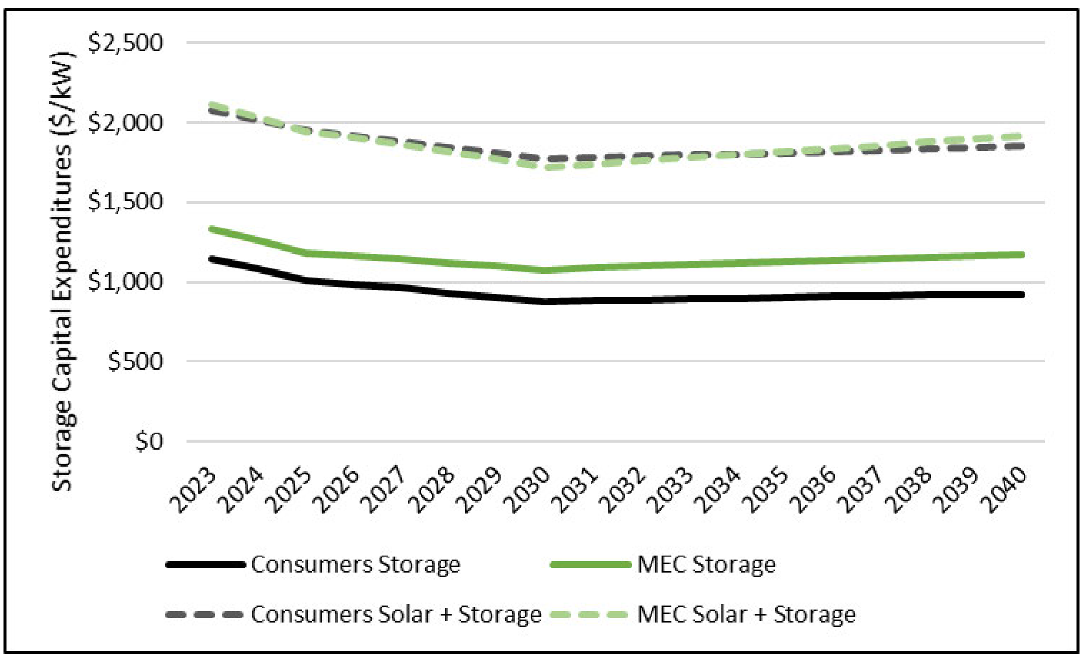


Figure 12: Capital Costs of Battery Storage and Solar-Battery Hybrids ($/kW nominal)[120]



[119] *Id.*

[120] *Id.*

Q. Please describe the two types of portfolios that you developed.

A. We developed two alternative portfolio types, both which included Covert and Livingston. Our exclusion of DIG and Kalamazoo was informed by CRA's analysis of their relative value as well as the inherent risks that these plants carry. We then constructed portfolios for two alternative pathways to the PCA: 1) a plan that maintained the Company's storage buildout but included capacity purchases (i.e., bilateral contract) to meet short-term capacity shortfalls in 2025 and the early 2030s[121]; and 2) a new build portfolio which fulfilled the 2025 capacity need with battery storage, and the 2030 capacity need with solar and storage.

B. Our plans show savings from the PCA in most cases.

Q. How did you treat the results between the CE gas and AEO gas price modeling?

A. Similar to Consumers, we developed versions of portfolios for runs with the AEO 2020 gas price and CE gas price, which include differences in capacity requirement (PRMR) as well. As Consumers points out, its gas price forecast is lower than the AEO 2020 gas price forecast, but the AEO 2021 forecast (which was not used) was slightly lower than the AEO 2020 in most years.[122] I view these two forecasts as low and high base cases and thus weighted the modeling results of the two equally.

Q. Please describe the results of the capacity purchase portfolios.

A. We developed portfolios that included Covert and Livingston, the Company's storage buildout in the PCA, expedited the solar PV from the PCA, excluded Kalamazoo and DIG,

[121] Under this portfolio, and using the CE gas price assumptions, Consumers would purchase 170 ZRCs in 2025, 299 ZRCs in 2030, 195 ZRCs in 2031, and 10 ZRCs in 2032.

[122] Walz Direct, pp. 12-13.

and purchased capacity when it was needed—2025, 2030, 2031, and 2032.[123] These purchases were all assumed to cost 75 percent of CONE, which is likely too high (as I explained previously in Section III of my testimony on capacity value). These capacity purchase portfolios produced savings relative to the PCA, averaging $138 million under the 50 percent CONE for the two gas prices—shown below in Figure 12. These results show that capacity purchases offer significant protection against the risk of lower capacity value which, as I described previously, is not only a real risk but is more reasonable than the 75 percent CONE value.

Figure 13: Savings (Costs) Under Capacity Purchase Portfolio ($mil NPV)

Capacity Purchases		100% CONE	75% CONE	50% CONE	25% CONE	0% CONE
BAU	AEO Gas	$148	$178	$208	$238	$268
	CE Gas	$17	$43	$68	$93	$119
	BAU Avg	**$83**	**$110**	**$138**	**$166**	**$193**

Q. Please describe the results of the new build portfolios.

A. These portfolios also included Covert and Livingston, expedited the solar PV from the PCA, excluded Kalamazoo and DIG, but new resources were built when needed including battery in 2025 (175 ZRCs), 2029 (190-195 ZRCs), 2030 (190-195 ZRCs) and 2040 (61-71 ZRCs).[124] The BAU results show savings relative to the PCA under the AEO gas runs and costs relative to the PCA under the CE gas runs. However, on average, there is savings under a 50 percent CONE or higher capacity value. Most runs performed under the ET and

[123] In our new build portfolio, purchased capacity was included in the AEO gas case in 2040. Notably, though, this assumption mirrors Consumers' PCA, which also included purchased capacity in 2040 under that case.

[124] The battery built in 2029 was to fulfill the capacity need in 2030 as well. The ranges for battery additions reflect the slight differences in buildouts between the CE gas and AEO modeling runs. The MNS new build AEO gas run, similar to Consumers' PCA under the AEO gas, includes a capacity purchase in 2040 only.

EP scenarios showed savings as well. Broadly, this type of portfolio offers protection against the risk of higher natural gas prices because it provides more savings under the AEO gas price than under CE gas. However, the capacity purchase results are more compelling under the BAU, especially if assuming lower capacity values.

Figure 14: Savings (Costs) Under Alternative New Build Portfolio ($mil NPV)

New Build		100% CONE	75% CONE	50% CONE	25% CONE	0% CONE
BAU	AEO Gas	$247	$228	$209	$190	$170
	CE Gas	($123)	($147)	($172)	($197)	($221)
	BAU Avg	**$62**	**$40**	**$18**	**($4)**	**($25)**
ET	AEO Gas	$479	$459	$440	$421	$402
	CE Gas	$32	$14	($4)	($22)	($40)
	ET Avg	**$255**	**$237**	**$218**	**$199**	**$181**
EP	AEO Gas	$144	$125	$106	$86	$67
	CE Gas	$140	$122	$104	$86	$68
	EP Avg	**$142**	**$124**	**$105**	**$86**	**$68**

Q. Does the alternative portfolio need to be either the capacity purchase plan <u>or</u> the new build plan?

A. No. An alternative plan could include a mix of the two tactics that we have taken: that is, it could have both capacity purchases and new builds. Given our modeling results in this case, I would recommend consideration of capacity purchases in 2025. If both Covert and Livingston are pursued but not DIG and Kalamazoo, there is a small shortfall in 2025 and no capacity needed again until 2030. Capacity purchases can be seen as a stop-gap solution but, in this case, that may be exactly what is warranted. For instance, [[[redacted]]]

Q. Are your alternative plans providing lower risk than Consumers' PCA?

A. Yes. The alternative plans provide better protection from critical risks such as fuel costs, technology costs, and carbon regulation. The PCA includes 2 GW of natural gas plants in the short-term, but this decision could lock in a large portion of the Company's energy system until at least 2040. The acquisition of all this gas is irreversible and forecloses opportunities to re-tool the Company's energy system by other means in that period. Renewable and battery storage costs have plummeted recently and storage technology in particular is improving. For instance, longer-duration battery storage is currently available and its costs are expected to plummet in the future—making it a more attractive marginal resource, especially in the medium or long-term.[125] (In this case, the Company and we only modeled 4-hour battery storage). The gas acquisition also makes ratepayers more vulnerable to higher natural gas prices and the potential for either carbon regulation or

[125] Frazier, A. Will, Wesley Cole, Paul Denholm, Scott Machen, Nathaniel Gates, and Nate Blair. *Storage Futures Study: Economic Potential of Diurnal Storage in the U.S. Power Sector*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77449, available at: https://www.nrel.gov/docs/fy21osti/77449.pdf. Table A-3, last checked October 22, 2021; see also "Secretary Granholm Announces New Goal to Cut Costs of Long Duration Energy Storage by 90 Percent," available at https://www.energy.gov/articles/secretary-granholm-announces-new-goal-cut-costs-long-duration-energy-storage-90-percent, last checked October 22, 2021.

more aggressive greenhouse gas emissions goals; these factors could lead the assets to become stranded at some point before 2040.

Q. Has Consumers previously objected to resource portfolios that include capacity purchases?

A. Yes. In the 2018 IRP case, Case No. U-20165, I testified that Consumers could have allowed for market purchases in its optimization portfolios but did not do so.[126] I also presented the NPV results of an alternative portfolio, modeled by MNS witness Evans, that included capacity purchases (i.e., bilateral contracts). In rebuttal and sur-surrebuttal, Consumers witness Walz raised two objections to Mr. Evans's modeling of a capacity purchases portfolio. First, witness Walz noted that under current law load serving entities may only plan to source up to 5 percent of their planning reserve margin requirement (PRMR) from the MISO PRA,[127] and criticized Mr. Evans's portfolio because it would require Consumers to purchase more ZRCs than the 5 percent PRA threshold allowed.[128] Second, Ms. Walz argued that if Consumers' portfolio included capacity purchases, the Commission might determine that Consumers had a capacity need – a determination that could force Consumers to fill that capacity need with long-term PURPA contracts.[129]

Q. Do you agree with these criticisms?

A. No. The first critique is misplaced because the 5 percent PRA limit does not apply to capacity purchased through bilateral contracts, and the alternative portfolio we presented

[126] Case No. U-20165, Revised Public Direct Testimony of Tyler Comings, 8 TR 1835.

[127] Case No. U-20165, Rebuttal Testimony of Sara T. Walz, 6 TR 496.

[128] Case No. U-20165, Walz Rebuttal, 6 TR 496-98.

[129] Case No. U-20165, Sur-Surrebuttal Testimony of Sara T. Walz, 6 TR 526.

reflected the costs of bilateral capacity contracts.[130] Contrary to Ms. Walz's testimony, our alternative portfolio in that case did *not* require procuring capacity through the PRA—and to be clear, the plan presented in my current testimony similarly does not involve PRA acquisitions. I believe the second critique is also misplaced, because it incorrectly assumes that the Commission would force Consumers to accept a long-term cost increase to address a short-term capacity shortfall.[131] Moreover, even if we were advocating for purchasing capacity from the PRA (which we are not), the amounts bought in our "capacity purchase" portfolio in this case are all below the 5 percent threshold.

Q. Do you have any further observations about Ms. Walz's testimony in U-20165?

A. Yes, in discussing MNS's alternative portfolio, she repeatedly referred to it as a plan that includes "the unspecified purchase of ZRCs."[132] Such characterization would be especially unwarranted in this case, for two reasons. First, [[[redacted]]] Second, Consumers failed to pursue contractual capacity sales as a resource option in the short or medium-term. Because Consumers has largely neglected to consider capacity purchases, if it once again raises these past objections to a capacity purchases alternative portfolio that I present, the Commission should disregard such arguments as unfounded.

---

[130] MNS addressed this issue in its Reply Brief in that case. See Case No. U-20165, Reply Brief of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club, p. 34.

[131] MNS discussed this issue in briefing as well. See *id.*, pp. 38-39. The Commission did not make findings on these issues, because that case was resolved by a settlement agreement.

[132] Case No. U-20165, Sur-Surrebuttal Testimony of Sara T. Walz, 6 TR 525-527.

VII. COMMUNITY TRANSITION PLANNING FOR KARN AND CAMPBELL SHOULD BE ROBUST AND TRANSPARENT.

Q. Please briefly describe the Karn generating units.

A. The Karn plant consists four generating units: coal-fired units 1 and 2, and oil/gas peaker units 3 and 4. Karn 1 and 2 are scheduled to retire in 2023; in the 2018 IRP case (No. U-20165), the Commission approved a settlement agreement that included this 2023 retirement.[133] Karn 3 and 4 are currently scheduled to operate until 2031, but in this case Consumers has proposed retiring units 3 and 4 in 2023 – thereby coinciding with the already established retirement date for the Karn 1 and 2 coal units.[134]

Q. What is the status of the Company's transition plan for the retirement of Karn units in 2023?

A. The Company developed a community transition plan in 2018 for the planned retirement of Karn units 1 and 2 in 2023.[135] In the previous IRP case, No. U-20165, Company witness Norman Kapala provided a high-level overview of this plan.[136] In the 2020 rate case, Consumers stated that it would update the community transition plan in late 2020;[137] but the 2018 plan has not been updated.[138]

[133] Case No. U-20165, June 7, 2019, Order Approving Settlement Agreement, Exhibit A, Para. 3.

[134] The Karn plant is part of a larger complex referred to the Karn-Weadock facility. The Weadock coal units retired in 2016. See Breining Direct, p. 6 n.1.

[135] Ex MEC-36, p. 1 (U20963-MEC-CE-659(a)(i)).

[136] Case No. U-20165, Direct Testimony of Norman J. Kapala, 8 TR 1147-48.

[137] Ex MEC-37, p. 1 (U20697-MEC-CE-549(a)).

[138] See Ex MEC-38, p. 1 (MEC-CE-089(b)). When asked to provide the most up-to-date version of this plan, the Company provided the 2018 plan.

Q. Are you concerned about the timeline for the Karn transition planning process?

A. Yes. Given that the Karn 1 and 2 coal units are retiring in 2023 and given the Company's proposal in this case to retire the remaining Karn units, it is important that transition planning for the Karn site move forward in the coming months. However, the Company has not established a timeline for updating the community transition plan.[139]

There are further reasons to be concerned about the pace of transition planning for the Karn site. Whereas the 2018 transition plan stated [[[redacted]]] And although the Company recently disclosed an alternatives analysis for the Karn site, this is [[[redacted]]], and the Company has acknowledged that "[a] future use study focused on the Karn Site has not been scheduled to-date."[142]

Q. Is the Company's transition plan publicly available?

A. No. The Company designated its community transition plan confidential and, therefore unavailable to the public and the affected community.[143] The Company has described the transition plan as "a business confidential document for Company use only."[144] While I

---

[139] Ex MEC-38, p.1 (MEC-CE-089(c)).

[140] Ex MEC-39C, p. 13 (U21090-MEC-CE-089-Kapala_CONF_ATT_2).

[141] Ex MEC-37, p. 4 (U206963-MEC-CE-028(h)).

[142] Ex MEC-38, p. 2 (MEC-CE-090(a)).

[143] See Ex MEC-39C (U21090_MEC-CE-089-Kapala_CONF_ATT_2).

[144] Ex MEC-37, p. 2 (U20697-MEC-CE-1029(a), (b) (admitted as Ex MEC-99 in Case No. U-20697).

understand that the plans may include specific competitively sensitive information, Consumers should still issue a public version of the plan. The existence of confidential data does not mean that the Company abdicates responsibility for informing the affected community.

Q. Has the Company engaged with the community on the transition plan?

A. To a limited extent. The Company started to have virtual meetings this year with "governing stakeholders" but these meetings were not open to the public.[145] The Company's engagement efforts appear to be focused on public officials and business leaders.[146]

Q. What do you recommend regarding the Karn retirement transition plan?

A. The Company should not wait for a final order on its PCA—which may not come until June of 2022—to move forward with the Karn transition plan. The time is running out, and the transition plan should be a priority, especially now that the entire Karn plant could retire in 2023. The Company should update its plan in earnest while recognizing and incorporating the public interest in the transition. The Company should provide more transparency by soliciting public input and providing a public version of the transition plan as soon as possible.

In the most recent DTE rate case (U-20561), the Commission directed DTE to file a comprehensive community transition plan for the retiring River Rouge power plant.[147] The

[145] Ex MEC-38, p. 2 (MEC-CE-090(c)).

[146] See Ex MEC-40 (ST-CE-172(c), 271-73).

[147] Case No. U-20561, May 8, 2020, Order, p. 189.

plan was supposed to "address public input DTE Electric has received through public meetings in River Rouge or other outreach to communicate the utility's plans with the community and receive input from community members,"[148] and the Commission noted the importance of "plans for a smooth retirement and community transition, accounting for plant employees, the impact on local tax base, site remediation, and other factors."[149] The utility was required to submit this plan approximately four-and-a-half months after the Commission's Order (and eight months before the plant's retirement).[150]

Consistent with that approach, the Commission direct Consumers to file a community transition plan for the Karn plant. The plan should be filed within 150 days of the final Order in this case, and the plan should be public.[151] The Company should also submit a study for the re-use of the Karn site or, if a study has not been completed, a status update on its future use planning efforts.

The Company should also begin transition planning for the Campbell coal units. Because those units are not proposed for retirement until 2025, there is more time to engage in transition planning. But the Company should be proactive and begin that process soon. And that process should have the same requirements discussed above with respect to Karn.

[148] Case No. U-20561, May 8, 2020, Order, p. 189.

[149] *Id.*

[150] Case No. U-20835, July 9, 2020, Order, p. 7.

[151] If any portions of the plan contain commercially or personally sensitive information, those portions can be redacted.

VIII. CONCLUSION AND RECOMMENDATIONS

Q. What do you recommend to the Commission?

A. For the reasons explained above I recommend the Commission:

- Recommend that Consumers modify the PCA by withdrawing its proposal to purchase DIG and Kalamazoo. Consumers could pursue a portfolio that includes Covert and Livingston but not DIG and Kalamazoo. The Company's revised PCA should consider:
  - Capacity purchases (i.e., bilateral contracts) to address the short-term capacity shortfall in 2025 (without Kalamazoo and DIG) and in the early 2030s;
  - Other replacement resource options such as solar-battery hybrids and standalone batteries; or
  - A combination of short-term capacity purchases and other resource options.
- Direct Consumers to file a community transition plan for the Karn plant within 150 days of the final Order in this case, and the plan should be public. The Company should also be directed submit a study for the re-use of the Karn site or, if a study has not been completed, a status update on its future use planning efforts. The Company should be encouraged to start a transition plan for the Campbell site.

Q. Does this conclude your testimony?

A. Yes.

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Tyler Comings, Senior Researcher
1012 Massachusetts Avenue, Arlington MA 02476 ⌘ tyler.comings@aeclinic.org ⌘ 617-863-0139

PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Arlington, MA. Senior Researcher, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. Senior Associate, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. Research Analyst, Economic Consultant, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. Billing Coordinator, Accounting Liaison, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

EDUCATION

Tufts University, Medford, MA

Master of Arts in Economics, 2007

Boston University, Boston, MA

Bachelor of Arts in Mathematics and Economics, Cum Laude, Dean's Scholar, 2002.

AFFILIATIONS

Society of Utility and Regulatory Financial Analysts (SURFA)
Member

Global Development and Environment Institute, Tufts University, Medford, MA.
Visiting Scholar, 2017 – 2020

CERTIFICATIONS

Certified Rate of Return Analyst (CRRA), professional designation by Society of Utility and Regulatory Financial Analysts (SURFA)

PAPERS AND REPORTS

Castigliego, J.R., T. Comings, S. Alisalad, and E.A. Stanton. 2021. *Background Report: Benefits of Coal Ash Cleanup and Remediation*. Applied Economics Clinic. Prepared for Earthjustice. [Online]

Woods, B., E. A. Stanton, T. Comings, and E. Tavares. 2019. *Emission Reduction Synergies for Massachusetts Community Choice Energy Programs, Heat Pumps and Electric Vehicles*. Applied Economics Clinic. Prepared for Green Energy Consumers Alliance. [Online]

Lopez, R., T. Comings, E.A. Stanton, and E. Tavares. 2019. *Home Heat Pumps in Massachusetts*. Applied Economics Clinic. Prepared for Green Energy Consumers Alliance. [Online]

Comings, T., B. Woods, and M. Majumder. 2019. *Updated Costs of Community Choice Energy Aggregation in Boston*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Comings, T., R. Lopez, and B. Woods. 2018. *A Critique of an Industry Analysis on Claimed Economic Benefits of Offshore Drilling in the Atlantic*. Applied Economics Clinic. Prepared for the Southern Environmental Law Center. [Online]

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Stanton, E.A., and T. Comings. 2018. *Massachusetts Clean Energy Bill Provisions Boost Jobs and Strengthen the State's Economy.* Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Stanton, E.A., T. Comings, R. Wilson, S. Alisalad, E.N Marzan, C. Schlegel, B. Woods, J. Gifford, E. Snook, and P. Yuen. 2018. *An Analysis of the Massachusetts 2018 'Act to Promote a Clean Energy Future' Report*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Comings, T., E.A. Stanton, and B. Woods. 2018. *The ABCs of Boston CCE*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Stanton, E.A., T. Comings, and A. Sommer. 2018.*The Husker Energy Plan: A New Energy Plan for Nebraska*. Applied Economics Clinic. Prepared for the Nebraska Wildlife Foundation. [Online]

Comings, T. and B. Woods. 2017. *The Future of the Martin Drake Power Plant*. Applied Economics Clinic. Prepared for Green Cities Coalition and Southeastern Colorado Renewable Energy Society. [Online]

Wilson, R., T. Comings, and E.A. Stanton. 2017. *Ratepayer Impacts of ConEd's 20-Year Shipping Agreement on the Mountain Valley Pipeline.* Applied Economics Clinic. Prepared for the Environmental Defense Fund. [Online]

Knight, P., A. Horowitz, P. Luckow, T. Comings, J. Gifford, P. Yuen, E. Snook, and J. Shoesmith. 2017. *An Analysis of the Massachusetts Renewable Portfolio Standard*. Synapse Energy Economics and Sustainable Energy Advantage. Prepared for NECEC in Partnership with Mass Energy. [Online]

Knight, P., S. Fields, F. Ackerman, T. Comings, and A. Allison. 2017. *Empowering Kentucky*. Synapse Energy Economics. Prepared for Kentuckians for the Commonwealth. [Online]

Comings, T. and A. Allison. 2017. *More Mileage for Your Money: Fuel Economy Increases While Vehicle Prices Remain Stable*. Synapse Energy Economics. Prepared for Consumers Union. [Online]

Cook, R., J. Koo, N. Veilleux, K. Takahashi, E. Malone, T. Comings, A. Allison, F. Barclay, and L. Beer. 2017. *Rhode Island Renewable Thermal Market Development Strategy*. Meister Consultants Group and Synapse Energy Economics. Prepared for Rhode Island Office of Energy Resources. [Online]

Fisher, J., P. Luckow, A. Horowitz, T. Comings, A. Allison, E.A. Stanton, S. Jackson, and K. Takahashi. 2016. *Michigan Compliance Assessment for the Clean Power Plan: MPSC/MDEQ EPA 111(d) Impact Analysis*. Prepared for Michigan Public Service Commission, Michigan Department of Environmental Quality, and Michigan Agency for Energy. [Online]

White, D., P. Peterson, T. Comings, and S. Jackson. 2016. *Preliminary Valuation of TransCanada's Hydroelectric Assets*. Prepared for the State of Vermont. [Online]

Comings, T., S. Jackson, and J. Fisher. 2016. *The Economic Case for Retiring North Valmy Generating Station*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Comings, T., A. Allison, and F. Ackerman. 2016. *Higher Fuel Economy Standards Result in Big Savings for Consumers*. Synapse Energy Economics. Prepared for Consumers Union. [Online]

Jackson, S., P. Luckow, E.A. Stanton, A. Horowitz, P. Peterson, T. Comings, J. Daniel, and T. Vitolo. 2016*. Reimagining Brayton Point: A Guide to Assessing Reuse Options for the Somerset Community.* Synapse Energy Economics. Prepared for Coalition for Clean Air South Coast, Clean Water Action, and Toxics Action Center. [Online]

Stanton, E.A., P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. R. Santen, and K. Takahashi. 2016. *The RGGI Opportunity 2.0: RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets*. Synapse Energy Economics. Prepared for Sierra Club, Pace Energy and Climate Center, and Chesapeake Climate Action Network. [Online]

Stanton, E.A., P. Knight, A. Allison, T. Comings, A. Horowitz, W. Ong, N. R. Santen, and K. Takahashi. 2016. *The RGGI Opportunity: RGGI as the Electric Sector Compliance Tool to Achieve 2030 State Climate Targets*. Synapse Energy Economics. Prepared for Sierra Club, Pace Energy and Climate Center, and Chesapeake Climate Action Network. [Online]

Ackerman, F. and T. Comings. 2015. *Employment after Coal: Creating New Jobs in Eastern Kentucky*. Synapse Energy Economics. Prepared for the Mountain Association for Community Economic Development. [Online]

Vitolo, T., M. Chang, T. Comings, and A. Allison. 2015. *Economic Benefits of the Proposed Coolidge Solar I Solar Project*. Synapse Energy Economics. Prepared for Coolidge Solar I, LLC. [Online]

Wilson, R., T. Comings, and E.A. Stanton. 2015. *Analysis of the Tongue River Railroad Draft Environmental Impact Statement.* Synapse Energy Economics. Prepared for Sierra Club and Earthjustice. [Online]

Synapse Energy Economics, Labor Network for Sustainability, and 350.org. 2015. *The Clean Energy Future: Protecting the Climate, Creating Jobs, and Saving Money*. [Online]

Fisher, J., T. Comings, F. Ackerman, and S. Jackson. 2015. *Clearing Up the Smog: Debunking Industry Claims that We Can't Afford Healthy Air*. Synapse Energy Economics. Prepared for Earthjustice. [Online]

Stanton, E. A., T. Comings, S. Jackson, and E. Karaca. 2015. *Atlantic Coast Pipeline Benefits Review*. Synapse Energy Economics. Prepared for Southern Environmental Law Center. [Online]

Takahashi, K., T. Comings, and A. Napoleon. 2014. *Maximizing Public Benefit through Energy Efficiency Investments*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Comings, T., S. Fields, K. Takahashi, and G. Keith. 2014. *Employment Effects of Clean Energy Investments in Montana.* Synapse Energy Economics. Prepared for Montana Environmental Information Center and Sierra Club. [Online]

Comings, T., J. Daniel, P. Knight, and T. Vitolo. 2014. *Air Emission and Economic Impacts of Retiring the Shawnee Fossil Plant*. Synapse Energy Economics. Prepared for the Kentucky Environmental Foundation. [Online]

Comings, T., K. Takahashi, and G. Keith. 2013. *Employment Effects of Investing in Select Electricity Resources in Washington State*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Stanton, E. A., T. Comings, K. Takahashi, P. Knight, T. Vitolo, and E. Hausman. 2013. *Economic Impacts of the NRDC Carbon Standard.* Synapse Energy Economics. Prepared for Natural Resources Defense Council (NRDC). [Online]

Ackerman, F., T. Comings, and P. Luckow. 2013. *A Review of Consumer Benefits from a Corporate Average Fuel Economy (CAFE) Standards*. Synapse Energy Economics. Prepared for Consumer Union. [Online]

Comings, T., P. Knight, and E. Hausman. 2013. *Midwest Generation's Illinois Coal Plants: Too Expensive to Compete? (Report Update).* Synapse Energy Economics. Prepared for Sierra Club. [Online]

Stanton, E. A., F. Ackerman, T. Comings, P. Knight, T. Vitolo, and E. Hausman. 2013. *Will LNG Exports Benefit the United States Economy?* Synapse Energy Economics. Prepared for Sierra Club. [Online]

Keith, G., S. Jackson, A. Napoleon, T. Comings, and J. Ramey. 2012. *The Hidden Costs of Electricity: Comparing the Hidden Costs of Power Generation Fuels*. Synapse Energy Economics. Prepared for Civil Society Institute. [Online]

Vitolo, T., G. Keith, B. Biewald, T. Comings, E. Hausman, and P. Knight. 2013. *Meeting Load with a Resource Mix Beyond Business as Usual: A regional examination of the hourly system operations and reliability implications for the United States electric power system with coal phased out and high penetrations of efficiency and renewable generating resources*. Synapse Energy Economics. Prepared for Civil Society Institute. [Online]

Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, and R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics. Prepared for Energy Future Coalition. [Online]

Bower, S., S. Huntington, T. Comings, and W. Poor. 2012. *Economic Impacts of Efficiency Spending in Vermont: Creating an Efficient Economy and Jobs for the Future*. Optimal Energy, Synapse Energy Economics, and Vermont Department of Public Service. Prepared for American Council for an Energy-Efficient Economy (ACEEE). [Online]

Comings, T. and E. Hausman. 2012. *Midwest Generation's Illinois Coal Plants: Too Expensive to Compete?*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Woolf, T., J. Kallay, E. Malone, T. Comings, M. Schultz, and J. Conyers. 2012. *Commercial & Industrial Customer Perspectives on Massachusetts Energy Efficiency Programs*. Synapse Energy Economics. Prepared for Massachusetts Energy Efficiency Advisory Council. [Online]

Hornby, R., D. White, T. Vitolo, T. Comings, and K. Takahashi. 2012. *Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky*. Synapse Energy Economics. Prepared for Mountain Association for Community Economic Development and the Kentucky Sustainable Energy Alliance. [Online]

Hausman, E., T. Comings, and G. Keith. 2012*. Maximizing Benefits: Recommendations for Meeting Long-Term Demand for Standard Offer Service in Maryland*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Tantia, P., M. Dimova, T. Comings, and K. Davis. 2012. *Budget Finance Company: A Loan Modification Case Study.* [Online]

Keith, G., B. Biewald, E. Hausman, K. Takahashi, T. Vitolo, T. Comings, and P. Knight. 2011. *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011*. Synapse Energy Economics. Prepared for Civil Society Institute. [Online]

Hausman, E., T. Comings, K. Takahashi, R. Wilson, W. Steinhurst, N. Hughes, and G. Keith. 2011. *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011*. Synapse Energy Economics. Prepared for the Vermont Department of Public Service. [Online]

Steinhurst, W. and T. Comings. 2011. *Economic Impacts of Energy Efficiency Investments in Vermont.* Synapse Energy Economics. Prepared for the Vermont Department of Public Service. [Online]

Datta, S., P. Tantia, and T. Comings. 2011. *WING Mobile Payments: A Product Design Case Study*. Ideas42. Prepared for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Kilimo Salama – Index-based Agriculture Insurance: A Product Design Case Study*. Ideas42. Prepared for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Emergency Hand Loan: A Product Design Case Study*. Ideas42. Prepared for International Finance Corporation. [Online]

Tantia, P. and T. Comings. 2011. *Commitment Savings Accounts in Malawi: A Product Design Case Study*. Ideas42. Prepared for International Finance Corporation. [Online]

Petraglia, L. and T. Comings, and G. Weisbrod. 2010. *Economic Development Impacts of Energy Efficiency and Renewable Energy in Wisconsin.* Economic Development Research Group and PA Consulting Group. Prepared for Wisconsin Department of Administration. [Online]

Economic Development Research Group. 2010. *The Economic Impact of Atlanta Hartsfield-Jackson International Airport*. Prepared for City of Atlanta. [Online]

Economic Development Research Group. 2009. *Economic Assessment of Proposed Brockton Power Facility*. Prepared for Brockton Power Company. [Online]

Economic Development Research Group and KEMA NV. 2009. *Economic Benefits of Connecticut's Clean Energy Program.* Prepared for the Connecticut Clean Energy Fund. [Online]

Howland, J., D. Murrow, L. Petraglia, and T. Comings. 2009. *Energy Efficiency: Engine of Economic Growth in Eastern Canada*. Economic Development Research Group and Environment Northeast. [Online]

Economic Development Research Group and KEMA NV. 2008. *New York Renewable Portfolio Standard: Economic Benefits Report*. Prepared for New York State Energy Research and Development (NYSERDA). [Online]

Colledge Transportation Consulting and Economic Development Research Group. 2008. *Northwest Corridor Trade and Manufacturing Strategy.* Prepared for Northern Development Initiative Trust and Canadian Manufacturers & Exporters. [Online]

Weisbrod, G. and T. Comings. 2008. *The Economic Role of the Gateway Transportation System in the Greater Vancouver Region*. Prepared for Greater Vancouver Gateway Council. [Online]

Cambridge Systematics and Economic Development Research Group. 2008. *Economic Impact Study of Completing the Appalachian Development Highway System*. Prepared for Appalachian Regional Commission. [Online]

Lynch, T., T. Comings, and G. Weisbrod. 2007*. Spatial Geography: Effects of Population Base and Airport Access*. Prepared for Appalachian Regional Commission. [Online]

BizMiner and Economic Development Research Group. 2007*. Program Evaluation of the Appalachian Regional Commission's Infrastructure and Public Works Projects*. Prepared for Appalachian Regional Commission. [Online]

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Mead & Hunt and Economic Development Research Group. 2007. *Oregon Aviation Plan 2007*. Prepared for Oregon Department of Aviation. [Online]

Economic Development Research Group. 2007. *The Economic Impact of Philadelphia Convention Center*. Prepared for Pew Charitable Trusts. [Online]

Economic Development Research Group. 2006. *Environmental Impacts of Massachusetts Turnpike and Central Artery/Tunnel Projects*. Prepared for the Massachusetts Turnpike Authority. [Online]

TESTIMONY AND EXPERT COMMENTS

Comings, T. 2021. *Testimony on Xcel Colorado's Energy Resource Plan.* Applied Economics Clinic. Prepared for Sierra Club and NRDC. [Online]

Comings, T., and J.R. Castigliego. 2021. *Comments on Evergy Missouri's Integrated Resource Plan.* Applied Economics Clinic. Prepared for Sierra Club. [Online]

Comings, T. 2021. Testimony on Consumers Energy 2021 rate case in Michigan. *Testimony to Michigan Public Service Commission on behalf of Michigan Environmental Council*, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan. Case No. U-20963. [Online]

Comings, T., J.R. Castigliego, S. Alisalad, E. Tavares (with Sierra Club). 2021. *Comments on Ameren Missouri's 2020 Integrated Resource Plan*. Comments to the Missouri Public Service Commission on behalf of Sierra Club. File No. EO-2021-0021. [Online]

Comings, T, R. Wilson, M. Goggin, and Sierra Club. 2021. *Comments on Xcel Energy IRP in Minnesota*. Comments to the Minnesota Public Utilities Commission on behalf of Sierra Club. Docket No. E002/RP-19-368. [Online]

Comings, T. 2020. *Testimony on Harrison and Fort Martin Coal Units in West Virginia.* Testimony to West Virginia Public Service Commission on behalf of Earthjustice. Case No. 20-0665-E-ENEC. [Online]

Comings, T. 2020. *Testimony on Four Corners Coal Units in Arizona.* Testimony to Arizona Corporation Commission on behalf of Sierra Club. File Nos. E-01345A-19-0236. [Online]

Comings, T. 2020. *Testimony on the Prudence of Fuel Costs of the Evergy Missouri Coal Fleet.* Testimony to Public Service Commission of the State of Missouri on behalf of Sierra Club. File Nos. EO-2020-0262 and EO-2020-0263. [Online]

Comings, T. 2020. *Testimony on Consumers Energy's Rate Case*. Testimony to the Michigan Public Service Commission on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club and Citizens Utility Board of Michigan, Case No. U-20697. [Online]

Comings, T. 2020. *Comments on Evergy's 2020 Integrated Resource Plan*. Comments to the Public Service Commission of the State of Missouri, File No. EO-2020-0280 EO-2020-0281. [Online]

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Comings, T. 2020. *Cost of Capital and Asset Return for Workers' Compensation Insurance in Massachusetts*. Applied Economics Clinic. Advisory Filing prepared for the State Review Board (SRB) of the Massachusetts Division of Insurance Docket No. R2019-01.

Comings, T. 2020. *Comments on Ameren Missouri Integrated Resource Plan*. Comments to Ameren Missouri on behalf of Sierra Club. [Online]

Comings, T. 2020. *Testimony on Indiana Michigan Power Company's Integrated Resource Plan*. Testimony to the Michigan Public Service Commission on behalf of Sierra Club, Case No. U-20591. [Online]

Comings, T. 2019. *Testimony on the Public Service Company of New Mexico's (PNM) Plan for Replacing the San Juan Coal Units*. Testimony to the New Mexico Public Regulation Commission on behalf of Coalition for Clean Affordable Energy (CCAE), Case No. 19-00195-UT. [Online]

Comings, T. 2019. *Testimony on Duke Energy Indiana's Coal Fleet*. Testimony to the Indiana Utility Regulatory Commission on behalf of Sierra Club, Cause No. 45253. [Online]

Comings, T. 2019. *Testimony on Sooner Coal Plant Scrubbers*. Testimony to the Oklahoma Corporation Commission on behalf of Sierra Club, Cause No. PUD 201800140. [Online]

Sierra Club, assisted by Comings, T., B. Woods, R. Lopez, and E. Tavares. 2019. *Comments on Southwestern Electric Power Company's Draft 2019 Integrated Resource Plan*. Comments to the Louisiana Public Service Commission on behalf of Sierra Club, Docket No. I-34715. [Online]

Sierra Club, assisted by Comings, T., B. Woods, R. Lopez, and E. Tavares. 2019. *Comments on Cleco Power's Draft 2019 Integrated Resource Plan*. Comments to the Louisiana Public Service Commission on behalf of Sierra Club, Docket No. I-34693. [Online]

Sierra Club, assisted by Comings, T., E.A. Stanton, and E. Tavares. 2019. *Comments on Xcel Energy Minnesota's 2018 Mankato Proposal*. [Online]

Comings, T., B. Woods, E.A. Stanton, and E. Tavares. 2019. *Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans*. Applied Economics Clinic. Prepared for Southern Environmental Law Center. [Online]

Comings, T. 2018. *Testimony on Consumers Energy Integrated Resource Plan (IRP)*. Testimony to Michigan Public Service Commission, Case No. U-20165. [Online]

Comings, T. 2018. *Testimony on the Economics of Karn Coal Units in Michigan*. Testimony to Michigan Public Service Commission, Case No. U-20134. [Online]

Comings, T. 2018. *Testimony on Vectren's Proposed Natural Gas Plant and Coal Retrofits*. Testimony to the Indiana Utility Regulatory Commission, Cause No. 45052. [Online]

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Comings, T. 2018. *Testimony on Stranded Costs of Public Service Company of Colorado's Comanche 1 & 2 Coal Units*. Testimony to the Public Utilities Commission of Colorado, Proceeding No. 17A-0797E. [Online]

Comings, T. 2017. *Testimony on the economic impact analysis of the proposed merger between AltaGas and WGL Holdings*. Testimony to the District of Columbia Public Service Commission, Formal Case No. 1142. [Online]

Comings, T. 2017. *Testimony on the economics of the proposed acquisition of the Pleasants plant*. Testimony to the West Virginia Public Service Commission, Case No. 17-0296-E-PC. [Online]

Fagan, B. and T. Comings. 2017. *Joint testimony regarding the economic analysis of the Maritime Link Project*. Testimony to the Nova Scotia Utility and Review Board, Matter No. 07718. [Online]

Comings, T., A. Horowitz, and K. Takahashi. 2017. *Comments on Portland General Electric's 2016 Integrated Resource Plan*. Comments filed with the Oregon Public Utility Commission, Docket LC 66. [Online]

Comings, T. 2016. *Testimony regarding Dayton Power & Light's proposed Distribution Modernization Rider and the value of the Company's coal fleet*. Testimony to the Ohio Public Utilities Commission, Cases No. 16-0395-EL-SSO, 16-396-EL-ATA, and 16-397-EL-AAM. [Online]

Comings, T. 2016. *Testimony evaluating the economics of Oklahoma Gas & Electric's application to install dry scrubbers at the Sooner generating facility*. Testimony to the Oklahoma Corporation Commission, Cause No. PUD 201600059. [Online]

Comings, T. and A. Horowitz. 2016. *Comments on Portland General Electric's Draft 2016 Integrated Resource Plan*. Comments filed with the Oregon Public Utility Commission, Docket LC 66. [Online]

Comings, T. 2015. *Testimony on the economic impacts of the proposed merger of NextEra Corporation and Hawaiian Electric Companies (HECO)*. Testimony to the Hawaii Public Utilities Commission, Docket No. 2015-0022. [Online]

Daniel, J., A. Napoleon, T. Comings, and S. Fields. 2015. *Comments on Entergy Louisiana's 2015 Integrated Resource Plan.* Synapse Energy Economics. Prepared for Sierra Club. [Online]

Comings, T., S. Jackson, and K. Takahashi. 2015. *Comments on Indianapolis Power & Light Company's 2014 Integrated Resource Plan.* Synapse Energy Economics. Prepared for Sierra Club. [Online]

Comings, T. 2014. *Testimony evaluating the assumptions and analysis used by FirstEnergy Ohio in support of its application for approval of an electric security plan and related Retail Rate Stability Rider*. Testimony to the Ohio Public Utilities Commission, Case No. 14-1297-EL-SSO. [Online]

Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

Comings, T. 2014. *Testimony evaluating the assumptions in the analysis supporting Oklahoma Gas & Electric's request for authorization and cost recovery of a Clean Air Act compliance plan and Mustang modernization*. Testimony to the Oklahoma Corporation Commission, Cause No. PUD 201400229. [Online]

Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities*. Testimony to the Maryland Public Service Commission, Case No. 9361. [Online]

Comings, T. 2014*. Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities*. Testimony to the State of New Jersey Board of Public Utilities, Docket No. EM14060581. [Online]

Comings, T. 2014. *Testimony on the economic impact analysis filed by Exelon Corporation and Pepco Holdings, Inc. in their joint petition for the merger of the two entities*. Testimony to the District of Columbia Public Service Commission, Formal Case No. 1119. [Online]

Daniel, J., T. Comings, and J. Fisher. 2014. *Comments on Preliminary Assumptions for Cleco's 2014/2015 Integrated Resource Plan*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

Fisher, J., T. Comings, and D. Schlissel. 2014*. Comments on Duke Energy Indiana's 2013 Integrated Resource Plan.* Synapse Energy Economics and Schlissel Consulting. Prepared for Mullet & Associates, Citizens Action Coalition of Indiana, Earthjustice and Sierra Club. [Online]

Comings, T. 2013. *Testimony regarding East Kentucky Power Cooperative's Application for Cooper Station Retrofit and Environmental Surcharge Cost Recovery*. Testimony to the Kentucky Public Service Commission, Case No. 2013-00259. November 27, 2013 and December 27, 2013. [Online]

Comings, T. 2013. *Testimony in the Matter of Indianapolis Power & Light Company's Application for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Gas Turbine Generation Facility*. Testimony to the Indiana Utility Regulatory Commission, Cause No. 44339. [Online]

Hornby, R. and T. Comings. 2012. *Comments on Draft 2012 Integrated Resource Plan for Connecticut.* Synapse Energy Economics. Prepared for AARP. [Online]

Resume dated October 2021

Question:

33. Refer to Walz workpapers WP-STW-2 and WP-STW-8.

a. Please provide the version of the glide path builder (WP-STW-8) that was used to develop the final PCA ("PCA" tab in WP-STW-2). If another calculation was used to develop the glide path for the final PCA, please provide such calculations.

b. In WP-STW-8, is it possible to develop a glide path that adds new incremental demand response after 2030?

   i. If so, please explain how such a glide path can be built.

   ii. If not, please explain why the glide path builder does not enable the addition of new DR tranches after 2030.

Response:

a. The PCA was not directly developed using WP-STW-8. The PCA was developed manually based on the resource selections and trends observed in the Aurora results across the 8 scenarios, as well as in consideration of the reliability, environmental, employee, community, customer rate and financial impact analyses. No calculations are available.

b. It is possible to develop a glidepath that adds new incremental demand response after 2030. Insert rows in the section starting on Excel row 289 and replicate how the other tranches were built, modifying the resource name in column B, the start date to the desired year in column V and the capacity in column F.

Sara T. Walz

Sara T Walz
September 18, 2021

Electric Supply Planning

Question:

33. Please address the following topics related to the RFP:

a. How did the Company select the RFP Administrator?

b. How were potential bidders notified of the RFP?

c. How were the types of products sought by the Company selected?

d. Has the Company or RFP Administrator received any complaints regarding the RFP process? If so, please explain.

e. How did the number of bidders in the current RFP compare to the number of bidders in each RFP conducted by the Company within the last 10 years?

Response:

a. The Company identified two organizations that met the needs of the Company and the parameters of the solicitation. After both were interviewed, the Company chose CRA based on several factors, including that CRA had previous experience facilitating Edgar/Allegheny compliant RFPs in which affiliates were permitted to participate. The other company the Company interviewed was not selected due in part to a conflict with a potential bidder(s).

b. As explained beginning on page 2 of Exhibit A-49 (KGT-5), a bidder outreach email was sent to potential respondents identified by the Company and CRA. Additionally, an advertisement was run in S&P Global Platts Megawatt Daily to capture any additional respondents.

c. The parameters of the Company's natural gas RFP are detailed in Witness Blumenstock's direct testimony Page 45 lines 12 through Page 46, lines 3, as well as my direct testimony, page 51, line 22 through page 52, line 19.

d. Neither the Company nor CRA have received any complaints regarding the RFP.

e. The Company has issued 4` RFPs for existing gas plants in the last 10 years. The following table details the number of bidders to each RFP:

RFP	# of Eligible Bidders
2012 Gas Plant RFP	5
2013 Gas Plant RFP	5
2017 Gas Plant RFP	2
2021 Gas Plant RFP	2

KEITH G. TROYER
October 20, 2021

Question:

3. Refer to Exhibit A-49, the March 12, 2021 letter from CRA to Consumers Energy Company, as well the related direct testimony of Jeffrey Battaglia and Keith Troyer:
a. Please produce a complete copy of all bids or offers submitted for the RFP, including all supporting documentation and any additional information provided to CRA following submission of the bid.
b. Please produce the pre-qualification applications submitted by the five potential bidders.
c. Please produce all communications (including but not limited to emails) involving CRA or Consumers Energy to or from the bidders in connection with the RFP process, including the three applicants who did not qualify for participation.
d. Please produce all evaluations, notes, documents, score sheets, modeling files, and workpapers used by CRA to evaluate the applicants or the bids at any stage of the RFP process. This includes any notes or other documents created in connection with the follow up conference calls that CRA conducted with representatives of the bidders.
e. Please produce all evaluations, notes, documents, score sheets, modeling files, and workpapers used by Consumers Energy to evaluate the applicants or the bids at any stage of the RFP process.
f. Further refer to page 3 of Exhibit A-49. Please produce all documents maintained or received on the CRA Information Website, including but not limited to all communications via the website.
g. Further refer to page 11 of Exhibit A-49.
i. If not already provided in response to subparts c and d, please produce each and every net present value (“NPV”) calculation prepared at any stage of the RFP process. Please also provide in machine-readable electronic format with formulas intact, all modeling files, including input and output files, and workpapers created, used, or relied on in preparing such NPV calculations.
ii. Please describe and produce a working copy of the dispatch model that CRA used to calculate NPVs of the RFP bids.
iii. Please produce a complete copy of any forecasts of natural gas, coal, market energy, and/or capacity prices that were used for CRA’s NPV calculations. For each forecast produced, please:
(a) Identify the person or firm that developed the forecast.
(b) Identify the date of the forecast.
(c) State whether the forecast in nominal or real dollars, and identify the assumed inflation rate.
iv. Did CRA conduct any sensitivities or alternative modeling runs on these NPV calculations? If so, please produce those sensitivity or alternative modeling analyses, including any workpapers and modeling input and output files (in electronic format with formulas intact).
h. Further refer to page 8 of Exhibit A-49. Please identify each of the “ongoing rate proceedings for DTE” being referenced in this portion of the opinion letter. Please also

specify whether the fuel delivery charge uncertainties referenced in this portion of the letter are referring to natural gas, waste gas, or both.
**For any document responsive to subparts a-h that originated in Excel, please produce the document in electronic Excel format with all inputs and all formulas intact.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request to the extent it is irrelevant and overly broad. Furthermore, by seeking "any" and "all" documents, the request is not narrowly tailored and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:

a. The eligible proposals as identified by CRA are attached to this response as U21090-MEC-003 CONFIDENTIAL Attachment 1. The Company does not possess proposal information related to ineligible proposals as identified and screened out by CRA.

b. The information requested is not available because it is not possessed by the Company. Pre-qualification applications were submitted by the five potential bidders directly to CRA.

c. The Company did not have any direct contact with the bidders during the RFP process and does not possess the communications between CRA and potential bidders. Email communications between the Company and CRA related to communications between CRA and bidders are provided as CONFIDENTIAL Attachment 2 to this response.

d. Please see the response to part a.

e. Consumers used the opinion letter provided by CRA to evaluate the bids. The opinion letter was filed as Exhibit A-49 (KGT-5) with my direct testimony in this case.

f. See Attachment 3 to this response that includes the solicitation documents and associated appendices maintained on the website.

g(i). CRA completed NPV analysis of the proposals submitted for each of the facilities. The analyses performed by CRA and delivered to the Company are attached as CONFIDENTIAL Attachment 4 to this response. Upon selection of the proposals, NPVs were also generated by the Company and are filed as Exhibit A-12 (STW-9) with the direct testimony of Company Witness Sara T. Walz in this case.

g(ii). See g(i) which includes modeling results.

g(iii). The natural gas and coal price forecasts were sourced from the 2020 U.S. Energy Information Administration Annual Energy Outlook report published January

2020. The market energy and capacity price forecasts were CRA model simulations developed in February and March 2021. The forecasts are in nominal dollars. For the assumed inflation rate, see the NPV models provided in g(i).

g(iv). No, we do not believe that CRA conducted any sensitivities or alternative modeling runs on these NPV calculations.

h. The "ongoing rate proceedings for DTE" reference Case No. U-20940. The fuel delivery charge uncertainties are referring to natural gas deliveries as addressed in that proceeding.

KEITH G. TROYER
August 4, 2021

CONSUMERS ENERGY COMPANY

REQUEST FOR PROPOSALS

Issued

January 6, 2021

Bids Due:

February 26, 2021 5:00 p.m. EPT (Jackson, MI)

Web Address: www.Consumers-RFP.com

Table of Contents

Appendices

1. Introduction

1.1 With this Request for Proposals ("RFP"), Consumers Energy Company ("CEC") is soliciting proposals for existing generation facilities available for acquisition by CEC as described more fully in Subsection 2.2 below. Within the context of this RFP, a "facility" can refer either to an entire electric generating station with multiple units or whole generating units representing a portion of such an electric generating station. If a Respondent (defined below) proposes to sell a portion of an electric generating station, the Respondent shall clearly state this in its Proposal (defined below) and describe in detail how costs incurred by the station as a whole would be allocated to the generating unit(s) the Respondent proposes to sell.

The general schedule for the RFP process is shown below (see also Subsection 3.5):

- Issue RFP January 6, 2021
- Non-Binding Notice of Intent Due January 20, 2021
- Pre-Qualification Applications Due January 20, 2021
- Notification of Pre-Qualification January 22, 2021
- Proposals Due February 26, 2021

1.2 CEC is the principal subsidiary of Jackson-based CMS Energy Corporation and is Michigan's largest electric and natural gas utility, providing service to almost 7 million of the state's 10 million residents in all 68 counties in the Lower Peninsula. CEC provides electric service to 1.8 million customers and serves 275 cities and villages in 61 counties. The Company owns and operates five (5) coal-fueled electric generating units[1], two (2) oil and gas-fueled electric generating units, nine (9) gas-fueled electric generating units, three (3) exhaust-fueled steam condensing electric generating units, thirteen (13) hydroelectric generating plants, one (1) six-unit (6-unit) pumped storage electric generating plant[2], three (3) wind-powered electric generating parks, three (3) solar photovoltaic electric generating systems and seven (7) combustion-turbine electric generating plants that produce electricity when needed during peak demand periods. The utility also purchases power from approximately seventy-five (75) sources, including the Palisades nuclear plant and the gas-fueled Midland Cogeneration Facility.

CEC is committed to providing a reliable supply of electric power to its customers. In order to ensure reliable, adequate capacity and energy supplies to meet the needs of its customers, CEC seeks to acquire new supplies of capacity, which at a minimum, meet industry-wide reliability and performance criteria and existing new source requirements for electric generation facilities.

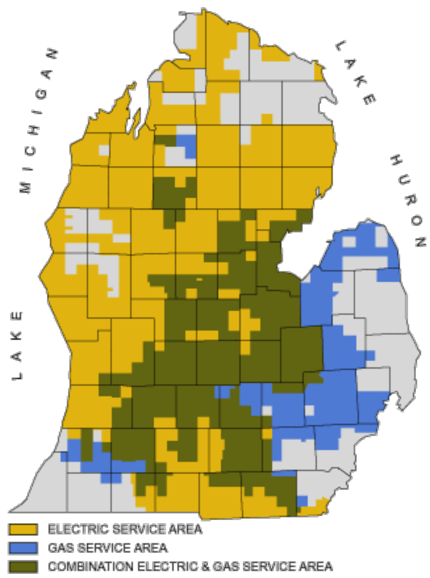
Accordingly, you are invited to submit a written proposal in accordance with the requirements described in this RFP. Specifically, CEC has retained Charles River Associates ("CRA") to manage the RFP process on behalf of CEC for the purpose of soliciting bids for CEC's acquisition of natural gas fueled simple cycle and combined cycle generating assets that meet the criteria set forth in Subsection 2.2 ("Product Description"). All proposals must meet the general requirements set forth in Section 4

[1] Ownership of one (1) coal-fueled electric generating unit limited to 93.31%.
[2] Ownership in the pumped storage plant is limited to 51%.

("RFP General Requirements"). All bidders with assets that meet the qualification requirements are invited to submit a bid or bids into the CEC RFP process.

CRA will serve as an independent third party to monitor and oversee the evaluation of all bids.[3] CRA shall administer this process through its website (see Subsection 3.1) on CEC's behalf in accordance with this RFP. Responses to this RFP will be accepted via the email Consumers-RFP@crai.com.

CONSUMERS ENERGY COMPANY
Service Territory



More information about CEC is available by visiting www.consumersenergy.com.

2. <u>Purpose / Desired Product</u>

2.1 <u>Purpose</u>

The purpose of this RFP is to solicit offers to sell existing electric generating facilities as described herein, located in that portion of the lower peninsula of the State of Michigan that is serviced by Midcontinent Independent System Operator, Inc. ("MISO"), or that could be reclassified to that portion of the lower peninsula of the State of Michigan that is serviced by MISO, and will meet the resource adequacy requirements as described in Module E of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (https://www.misoenergy.org/legal/tariff/) and MISO's applicable Business Practice Manuals (https://www.misoenergy.org/legal/business-practice-manuals/) applicable to CEC.

[3] See, *Allegheny Energy Supply Co., LLC,* 108 FERC ¶ 61,082 (2004) (Allegheny), where the Commission enumerated four principles of a competitive solicitation and the role of the independent third party in meeting those principles.

2.2 **Product Description**

CEC will consider proposals to acquire existing simple cycle or combined cycle natural gas-fueled electric generating facilities which are in service and operational as of the date of this RFP ("Proposals"). CEC is seeking to acquire one or more facilities that have a capacity up to 1,400 MW on a MISO Unforced Capacity ("UCAP") basis in total at a single site and up to approximately 2,000 MW in aggregate. Such Proposals must be consistent with the size and acquisition date requirements specified in Subsections 4.2, 5.3 and 5.4. The physical location of such facilities must be in that portion of the lower peninsula of the State of Michigan that is serviced by MISO. CEC seeks Proposals for the purchase of 100% of the specified generating facilities. Pricing will be based on a single fixed payment that is inclusive of all monetary consideration for the generating assets and, if applicable, ancillary facilities and other contractual arrangements. Any such other contractual arrangement (e.g., other offtake agreements, fuel supply, fuel transportation, maintenance agreements, waste heat payments, steam host payments, pipeline leases, cooling or make-up water supply, blow down water disposal, emission allowances, etc.) should be clearly defined in the Proposal.

In some cases, facilities offered in this RFP may have existing offtake agreements with CEC. In such cases, bidders should assume the abrogation or termination of any such agreements as of the date of the asset transfer. CEC will consider the economic value of any such termination in the economic analysis of bids.

3. **Information and Schedule**

3.1 **Information Provided to Potential Respondents**

This RFP and all of its appendices and forms, except the proposed purchase and sale agreement ("PSA"), are anticipated to be available as of January 6th, 2021 on CRA's website (www.Consumers-RFP.com). The PSA will be provided as soon as possible thereafter, likely during the week of January 11. Interested parties are expected to be able to download the RFP with its required forms and complete the forms in Microsoft Word and/or Excel format. Respondents (defined below) shall submit properly completed forms by the specified deadline by electronic mail to the RFP Submission Email Address (Consumers-RFP@crai.com).

Respondents with Proposals over 30 MB in size should contact CRA for instructions on how to submit a Proposal via CRA's secure Web Transfer platform. Proposals that are nonconforming, not complete, or that are mailed, or hand delivered may be deemed ineligible and may not be considered for further evaluation. Any Proposals received from a Respondent that has not been pre-qualified will be deemed ineligible and will not be considered for further evaluation.

Please note that the RFP Manager (CRA) will always confirm receipt of a Proposal. Bidders that do not receive a bid confirmation should notify the RFP Manager.

CRA anticipates sending an electronic mail notice to parties that it considers likely participants in this RFP. The preparation of a Proposal may be initiated at any time provided that such preparations are completed in accordance with the instructions found in this RFP.

By submitting a Proposal in response to this RFP, the party submitting the Proposal ("Respondent") certifies that it has not divulged, discussed or compared any commercial terms of its Proposal with any other actual or prospective Respondent and has not colluded whatsoever with any other party believed to be an actual or prospective Respondent.

3.2 Information on the RFP Website

The information on CRA's website will contain the following:

(a) This RFP

(b) Form of Non-Disclosure Agreement ("NDA")

(c) Pre-Qualification Document(s)

(d) Form of Purchase and Sale Agreement ("PSA")

(e) Evaluation Criteria

(f) Standard RFP Response Form

(g) Frequently asked questions ("FAQ") about this RFP

(h) Updates on this RFP process and other relevant information

3.3 Questions

All questions regarding this RFP should be submitted to the RFP Submission Email Address (Consumers-RFP@crai.com). All relevant questions and answers will be posted to the RFP website and made available to all process participants. Other than questions and answers submitted through the RFP Submission Email Address and posted on the RFP website, no other individual or bidder specific explanations or interpretations of this RFP will be given. Written questions will be accepted by CRA until five (5) days before the date on which Proposals are due. The Respondent should check the web site periodically for updates and postings.

In the event that a given Respondent has a question or seeks clarification or explanation of any data or information provided in this RFP, such Respondent is responsible for obtaining the desired information by submitting a written question to CRA through the RFP Email Address by no later than five (5) days before the date on which Proposals are due.

Any and all communications regarding this RFP will be submitted through the RFP Email Address, posted on the RFP website or communicated through a public bidder information session. Under no circumstance should Respondents attempt to contact CEC employees directly with any matters related to this RFP.

3.4 Clarification of Proposals

While evaluating Proposals, CRA may request additional information about any item in the Proposal. All requests will be made in writing, and the Respondent will be required to respond to the request within five (5) business days of receipt of such request or CRA may choose to stop evaluating the Respondent's Proposal.

3.5 Schedule

The following schedule and deadlines apply to this RFP. CEC reserves the right to extend or otherwise modify any portion of this schedule at any time or terminate the RFP process at its sole discretion.

3.5.1 EPT or Eastern Prevailing Time means Eastern Standard Time or Eastern Daylight Savings Time, whichever is in effect in Jackson, Michigan on any date specified.

3.5.2 All Proposals are due by 5:00 p.m. EPT, February 26, 2021. Proposals received after the specified date and time will be disqualified from further evaluation.

Step	Timetable
Notice of Intent Due and Non-Disclosure Agreement Due	5:00 p.m. EPT, January 20, 2021
Respondent Pre- Qualification Application Due	5:00 p.m. EPT, January 20, 2021
Respondents Notified of Results of Pre-Qualification Application Review	5:00 p.m. EPT, January 22, 2021
Proposal Due Date	5:00 p.m., EPT, February 26, 2021
Proposal Evaluation Completion Target	March 26, 2021
Enter into Definitive Agreement Phase	April 2021 (tentative)

4. RFP General Requirements

Proposals that do not meet the following criteria will be deemed to be ineligible and not be considered for further evaluation.

4.1 Respondent Pre-Qualification

To be eligible to submit a Proposal in response to this RFP, Respondents must be pre-qualified. To pre-qualify, Respondents must:

(a) Submit (i) a Notice of Intent (Appendix A), (ii) a completed Non-Disclosure Agreement (Appendix B), and (iii) a completed Pre-Qualification Application (Appendix C) through the RFP Submission Email Address (Consumers-RFP@crai.com) no later than the date and time specified pursuant to Subsection 3.5.2 above; and

(b) Receive confirmation from CRA that Respondent is pre-qualified to submit a Proposal.

4.2 **Facility Parameters**

Each specific generating facility proposed for purchase by CEC under a Proposal must:

(a) Be in service and operational as of the issuance date of this RFP.

(b) Have a MISO resource adequacy capacity rating so as to produce no less than 50 MW of UCAP and no greater than 1,400 MW of UCAP.

(c) Have a physical location in that portion of the lower peninsula of the State of Michigan that is serviced by MISO (currently designated as Local Resource Zone 7 ("LRZ7")) or be capable of qualifying or reclassifying as a MISO LRZ7 resource.

(d) Consist of a simple cycle or combined cycle natural gas-fueled generating facility.

(e) Have all relevant environmental and other permits necessary for its operation and maintenance.

(f) Be comprised of a 100% share of the facility.

4.3 **Proposal Quantities and Pricing**

This RFP requests Proposals that consist of a firm price for the specified generating facility. All prices must not be tied to any contingencies other than as specified herein. In the event that multiple Proposals for different facilities are submitted by the same Respondent, Respondent must indicate whether or not the Proposals are mutually exclusive.

4.4 **Valid Proposal Duration**

Proposal pricing must be valid for six (6) months following the Proposal Due Date, upon which time Proposals shall expire unless the Respondent has been notified that its Proposal has been selected.

5. **Proposal Content Requirements**

This section describes CEC's expectations and requirements for the content of Proposals. Proposals that do not meet the following criteria will be deemed to be ineligible and not be considered for further evaluation. CEC expects Respondents to provide any information that could impact the Respondent's ability to sell the facility as offered. If it appears that certain information is inadvertently omitted from a Proposal, CRA may contact the Respondent to obtain the information.

All Proposals must include a table of contents and provide concise and complete information on all of the following topics:

5.1 **Standard RFP Response Form**

Respondents shall provide a completed Appendix E, Standard RFP Response Form. Be advised that Appendix E does not capture all of the information required to be provided in this RFP.

5.2 Executive Summary

Proposals must include an executive summary of the Proposal's characteristics including any unique aspects and benefits.

5.3 Name and Location

Respondents shall state the name of the generating facility, the county where the generating facility is located, the owner of the facility, the MISO Commercial Pricing Node associated with the facility and the commercial in-service date for the facility. The location must be in that portion of the lower peninsula of the State of Michigan that is serviced by MISO (currently designated as Local Resource Zone 7), or that could be reclassified and serviced by MISO.

5.4 Net Capability of Generating Facility

Respondents shall state the net capability of the facility that would be applicable for each month of a calendar year as well as the nameplate capacity of the facility. In no event shall any Proposal include a generating facility that is capable of producing less than 50 MW of UCAP or likely to produce more than 1,400 MW of UCAP.

5.5 Acquisition Date

In preparing their Proposals, Respondents shall assume that the acquisition of the facility would be closed and title transferred on or about a date ranging from approximately April 30, 2023 to April 30, 2026.

5.6 Generation Technology

Respondents shall describe the generation technology of the facility, including the make of the equipment, model and name of supplier. Such technology must consist of a simple cycle or combined cycle natural gas-fueled generating facility.

5.7 MISO UCAP

Respondent shall list the UCAP awarded to the facility for the five (5) most recent MISO Planning Years and the projected UCAP for the next three (3) years. In the event that the projected UCAP has sizable deviation from historical UCAP, Respondents shall provide a detailed explanation.

5.8 Heat Rate and Emission Rates

Respondents shall provide the current operating heat rate curve (e.g., the coefficients of a fifth-order equation), the no-load cost, the average heat rate at minimum load, incremental heat rates at 50% and 75% of full load, the average full load heat rate of the facility (without duct firing), and the incremental heat rate for duct firing. Respondents shall also provide a summary of any environmental control equipment installed at the facility and emission rates for NOx, SO_2, CO_2, VOC, PM and CO in units of lb/MMBTU.

5.9 Operating Costs and Revenues

Respondents shall state the estimated annual operation and maintenance costs of the facility on a fixed ($) and variable ($/MWh) basis (Long Term Service Agreement fixed and variable costs should be listed separately from other fixed and variable costs) and provide the actual annual operation and maintenance costs of the facility for each of the past three (3) years. Respondents shall also state and describe any property taxes and tax abatements associated with the facility, including actual annual property taxes for the past three (3) years and estimated property taxes for the facility for the next three (3) years.

Respondents shall provide for the past three (3) years and estimated for the facility for the next three (3) years all energy market revenues, capacity market revenues and ancillary services revenues for the facility. If the facility has or is expected to generate any other market revenues (costs), the respondent should provide such information and describe the source of the facility revenue.

Respondents shall provide detailed timing and cost information on each of the major planned and forced outages for each of the past three (3) years. Respondents shall provide estimated timing and cost information for the next major planned outage events for the generating units.

5.10 **Capital Expenditures**

Respondents shall identify the total number of operating hours and remaining life for each major turbine component subject to replacement and/or refurbishment as part of the major maintenance cycle. Respondents shall provide historical and budgeted capital expenditures for the facility. Historical capital expenditures shall be provided for each of the past three (3) years. Budgeted capital expenditures shall be provided for each of next three (3) years along with a description of the projects involved.

Respondents shall supply a summary list of all spare parts and components currently owned by the facility and each part's and component's approximate value for parts and components valued at $10,000 or more. Respondents shall also identify any spare parts or components valued at $10,000 or more that are currently needed and/or on order as of the date of this RFP.

5.11 **Fuel Supply**

Respondents shall provide a description, including detailed cost information, of all existing fuel and transportation contracts that would be assigned to CEC in an acquisition. Respondents must also state whether or not there are any provisions or other considerations that would prohibit the assignment and/or affect the performance obligations of either party under the respective contract. Respondents should fully detail how fuel is purchased and transported to the facility as well as any existing or known potential operational restrictions or impediments on such fuel supply. Respondents are also required to provide a description of the existing natural gas infrastructure serving the generating unit.

5.12 **Other Contractual Commitments**

Respondents shall provide a description, including detailed cost information, of any other significant contracts that would be assigned to CEC in an acquisition, including, but not limited to, offtake agreements, long-term service agreements, state union labor contracts and/or technical support contracts, steam supply agreements, waste heat supply agreements, cooling water or make-up water supply agreements, blow-down water disposal agreements, steam transport agreements, pipeline lease agreements, fuel supply agreements, fuel transportation agreements, emission allowance agreements, and agreements related to capacity and/or energy sales from the facility and any capacity offers submitted to any ISO/RTO related to the facility that if accepted would be binding on CEC as a result of an acquisition. Respondents must also state whether or not there are any provisions that would prohibit the assignment and/or affect the performance obligations of either party under the respective contract.

5.13 **Permits**

The facility must have all relevant environmental and other permits necessary for its operation and maintenance. Respondents shall provide a description of all permits currently in place for the operation and maintenance of the facility (e.g. Spill Prevention Containment and Control plans, Title IV and Title V permits of the Clean Air Act, Cap and Trade Permits, NPDES permits, Water Withdrawal, Pollution Incident Prevention Plan). Respondents must also state whether or not there are any provisions that would prohibit the assignment of such permits and/or any consents required for the assignment of the permit.

Respondents shall provide a description of any identified environmental liabilities (e.g., potential site remediation requirements, pending future regulatory requirements, etc.) for the facility.

5.14 **Dispatch Characteristics**

Respondents shall state/describe the dispatch characteristics of the facility, including, but not limited to, minimum load level, ramp rates (up and down), number of gas turbines that can be started simultaneously (if applicable), fuel consumption during startup, capability decreases as a result of ambient temperature increases (indicate if inlet chilling or evaporative cooling is present on the unit(s)), supplemental firing capability (including peak firing capability and historical power augmentation usage and availability) and any operating limitations caused by such factors as design, material condition of the facility, and various permit restrictions. In addition, Respondents shall indicate if the unit(s) are capable of black start and the range of Automatic Generation Control (if applicable).

Regarding any major operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g., OEM design, material condition of the facility, environmental permits, etc.).

5.15 **Operating Data**

Respondents shall provide historical operating data consisting of: (1) net unit generation in MWh, (2) the commercial operation date of the facility, (3) the annual run-time hours (per unit, if applicable), (4) the annual facility capacity and availability factors, (5) the annual average heat rate, and (6) MISO equivalent forced outage rate demand (XEFORd). The above annual data may be limited to the most recent five (5) years. The XEFORd should correspond to the Unforced Capacity amounts awarded for the last five (5) Planning Years. Respondents shall also provide a forecast of the facility's forced outage rate and planned outage days for each of the next three (3) years.

Respondents shall also provide: (1) An identification of the heat rate during startup of the facility, and identification of the time startup takes, (2) a description of the total number of annual hours the facility can be assumed to be in startup mode, (3) the heat input required for startup, (4) the average MWh produced while ramping to meet dispatch, (5) the average run-time per start, (6) an identification of the heat rate of the facility when it is being shut down and a description of how long shutdown takes, (7) the average MWh produced while ramping to come off-line, (8) an identification of the annual hours the facility is in shutdown mode, (9) an identification of the annual hours the facility operates at full load, and (10) the number of annual hours that exclude startup and shutdown where the facility operates at less than full load and the corresponding heat rate.

Respondents shall provide details on any equipment health issues and concerns, including the potential drivers and recommended mitigation procedures for the issues and/or concerns. These may include, but are not limited to, turbine startup vibration, uneven heating, compromised turbine or compressor blades, etc.

Respondents shall provide a list of any redundant equipment that is currently bypassed or out of service because it is non-functional.

Respondents shall provide maintenance history consisting of: (1) dates of last full unit inspection and findings based on OEM recommendations, (2) total number of equivalent starts and equivalent operating hours on each unit, (3) equivalent starts and equivalent hours since the last major maintenance activity, and (4) outstanding OEM recommendations remaining to be implemented.

5.16 Acquisition Price

Respondents shall submit an acquisition price consisting of a single fixed payment that is inclusive of all monetary consideration for the generating assets, working inventory, and, if applicable, ancillary facilities and other contractual arrangements (e.g. for fuel supply and transportation, maintenance, etc.).

5.17 Purchase and Sale Agreement

This RFP includes a proposed form of PSA (Appendix D), which will be provided as soon as possible. Respondents shall submit a "mark-up" of the PSA containing any comments thereon proposed for consideration as part of Respondent’s Proposal. Respondents should download the PSA from the RFP website (www.Consumers-RFP.com) (see Subsection 3.2) and submit comments in red-lined form to the RFP Submission Email Address (see Subsection 3.1) by the Proposal Due Date.

6. Minimum Bid Eligibility Requirements

This section outlines the minimum requirements that all Proposals must meet to be eligible to participate in this RFP. Proposals unable to meet the following criteria will be deemed to be ineligible and not be considered for further evaluation.

- Respondents must meet the general requirements in accordance with Section 4 of this RFP.
- Proposals must include all content requirements described in Section 5 of this RFP, including all requested information and completed forms.

- Proposals must demonstrate that the generating facility meets industry-wide reliability and performance criteria and existing new source requirements for electric generation facilities.

7. Bid Evaluation and Contract Negotiations

7.1 Initial Proposal Review

After the Proposal Due Date, CRA will review all responses for completeness, responsiveness and compliance with the minimum bid eligibility requirements specified in Section 6 of this RFP. CRA will not accept updated pricing from Respondents during the evaluation period unless such information is requested by CRA. Preliminary due diligence will also be conducted at this stage to identify any flaws associated with the bid that would make it unacceptable. As a result of this screening, CRA may either eliminate bid(s) from further consideration, or contact Respondent(s) to clarify information or request additional information. CRA will make such requests in writing via email and Respondents will be required to respond to the request within five (5) business days of receipt of such request or CRA may choose to stop evaluating a Respondent's Proposal (see Subsection 3.4).

7.2 Shortlist Development

Proposals that meet the requirements in Section 6 will be evaluated consistent with the process detailed in the Evaluation Criteria document (Appendix F) posted to the RFP website. Points will be awarded to and deducted from proposals in accordance with the process outlined. Proposals will be evaluated based on:

1. Proposal Net Present Value over the period commencing from the anticipated acquisition date

2. Demonstrated and Expected Asset Reliability

3. Asset or Proposal Specific Benefits and Risk Factors

CEC anticipates purchasing the asset or assets that, in total, best meet customer needs. Bids will be rank ordered based on the stated evaluation criteria and assets will be selected for advancement based on CEC's capacity needs. Consistent with that objective, CEC may need to purchase multiple generating assets. In order to secure the overall portfolio of assets that best meets CEC's capacity needs, there is no assurance that the individual, highest-scoring qualified proposal(s) will be selected due to the fixed MW associated with each individual bid.

During the evaluation process, CEC and/or CRA may choose to initiate discussions with one or more Respondents. In that event, CRA will be the sole conduit of information between Respondent and CEC. Discussions with a Respondent shall in no way be construed as commencing contract negotiations.

7.3 Contract Negotiations / Definitive Agreements

CEC's commencement of and participation in negotiations shall not be construed as a commitment to execute a PSA. Only execution of a Definitive Agreement (an agreement executed by both CEC and the Respondent on mutually acceptable terms) will constitute a "Winning Proposal".

8. **Credit Qualification and Collateral**

Bidders submitting "Winning Proposals" may be required to post collateral at the time of execution of Definitive Agreements. CRA and CEC will evaluate the credit quality and related collateral posting requirements for each Respondent submitting a Proposal(s) in accordance with a uniform and consistent application of CEC's risk management practices and standards, in two phases: (i) as part of CRA's evaluation of a Respondent's pre-qualification application; and (ii) if a Respondent is selected, during the negotiation of the Definitive Agreement.

Credit worthiness requirements are as follows:

Respondent counterparties that have a minimum investment grade credit rating shall be deemed to have met the credit worthiness standard and shall not be required to post Definitive Agreement Collateral ("DA Collateral"). A minimum investment grade credit rating is defined as the most recently published unsecured senior long term debt rating (or corporate issuer rating if unsecured long term debt rating is not available) of **BBB** or **Baa2** from Standard & Poor's (S&P) or Moody's Investor Service (Moody's), respectively.

- If a Respondent counterparty is either not rated by the aforementioned public rating agencies or has ratings below investment grade as defined above, the creditworthiness standard may be met by issuing a corporate guaranty from an acceptable credit support provider that satisfies the above minimum investment grade standard.

- CEC's acceptance of a corporate guaranty shall be subject to a satisfactory review of the credit support provider that is issuing the guaranty. In addition, the guaranty shall be in a form acceptable to CEC.

Any Respondent that does not meet the above creditworthiness requirements (or provide an acceptable guaranty) shall have the corresponding obligation to post DA Collateral as determined by CEC and codified in the Definitive Agreement only if selected as a Winning Proposal for the Definitive Agreement phase of this RFP. DA Collateral must be posted at the execution of the Definitive Agreement and will be in force until the transfer of title to CEC. The amount and form of DA Collateral will be subject to negotiation at the time of execution of the Definitive Agreement.

9. **Reservation of Rights**

CEC reserves the right, without qualification, to reject any or all Proposals and to waive any irregularity in submitted information. There is no assurance, expressed or implied, that any agreement will be executed pursuant to this RFP. CEC may terminate negotiations with any bidder at any time without liability.

Bidders are advised that any agreement executed by CEC and any selected respondent may not be an exclusive contract. In submitting a proposal, bidders will be deemed to have acknowledged that CEC may contract with others for the same or similar deliverables or may otherwise obtain the same or similar deliverables by other means and on different terms.

CEC also reserves the right to evaluate all Proposals received in any manner it elects to employ, to solicit additional Proposals if it is deemed necessary to do so and the right to submit additional information requests to Respondents during the Proposal evaluation process.

This RFP shall not, by itself, give any right to any party for any claim against CEC. Furthermore, by submitting a Proposal, the Respondent shall be deemed to have acknowledged that CEC assumes no liability in any fashion with respect to this RFP or any matters related thereto. By submission of a Proposal, the Respondent, for itself as well as for its successors and assignees (if any), agrees that, as between Respondent and CEC, Respondent is to be solely responsible for all claims, demands, accounts, damages, costs, losses and expenses of whatsoever kind in law or equity, known or unknown, foreseen or unforeseeable, arising from or out of this RFP.

CEC shall not reimburse Respondent and Respondent is responsible for any cost incurred in the preparation or submission of a Proposal, in negotiations for an agreement, and/or any other activity contemplated by the Proposal submitted in connection with this RFP.

10. **Confidentiality of Information**

All Proposals submitted in response to this RFP become the property of CEC upon submittal. Respondents should clearly identify each page of information considered to be confidential or proprietary. Consistent with the NDA, CEC will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all information so identified. CEC reserves the right to release any Proposals to agents or consultants for purposes of Proposal evaluation. Regardless of the confidentiality claimed, however, and regardless of the provisions of this RFP, all such information may be subject to review by the appropriate state authority, or any other governmental authority or judicial body with jurisdiction relating to these matters, and may also be subject to discovery by other parties. CEC will not release any of the Respondent's confidential information to any of its affiliates who respond to the RFP.

11. **Regulatory Approvals**

11.1 Respondent agrees to cooperate, to the fullest extent necessary, to obtain any and all State, Federal, or other regulatory approvals CEC deems to be required for the effectiveness of the PSA.

11.2 The PSA shall be subject to and contingent on CEC obtaining Michigan Public Service Commission approval of CEC's application for approval of its integrated resource plan in a form that is acceptable to CEC and not subject to further appeal.

11.3 The PSA may be subject to and contingent on CEC obtaining authorization from the Federal Energy Regulatory Commission for the acquisition of assets from Respondent pursuant to Section 203 of the Federal Power Act.

11.4 The PSA shall also be subject to and contingent on CEC obtaining Michigan Public Service Commission approval that the costs of assets purchased pursuant to a Definitive Agreement will be recoverable in the rates charged to CEC's jurisdictional customers.

MEC-19C

CONFIDENTIAL EXHIBIT

MEC-20C

CONFIDENTIAL EXHIBIT

MEC-21C

CONFIDENTIAL EXHIBIT

MEC-22C

CONFIDENTIAL EXHIBIT

MEC-23C

CONFIDENTIAL EXHIBIT

Question:

6. Please identify any Company Aurora cases (by Run ID) in which Karn units 3 and 4 are retired in 2023 and Campbell units 1, 2 and 3 are retired in 2025, which developed an optimal expansion plan without the manual selection of the Covert and CMS plants.

Response:

All Consumers Energy Aurora cases in which Karn units 3 and 4 are retired in 2023, and Campbell units 1, 2 and 3 are retired in 2025 include the manual addition of Covert, Dearborn, Kalamazoo and Livingston.

Sara T. Walz

Sara T Walz
August 18, 2021

Electric Supply Planning

Question:

12. Refer to the Direct Testimony, exhibits, and workpapers of Sara T. Walz.
a. Did Consumers perform any Aurora model runs that assumed (i) the acquisition of Covert plant in 2023 and (ii) the acquisition of a subset of the CMS units? If so, please identify each of those model runs (by Run ID as shown in workpaper WP-STW-1) and provide the NPV for each such run.
b. Did Consumers perform any Aurora model runs that assumed (i) the acquisition of Covert plant in 2023 but (ii) the acquisition of none of the CMS units? If so, please identify each of those model runs (by Run ID as shown in workpaper WP-STW-1) and provide the NPV for each such run.
c. Did Consumers perform any Aurora model runs that assumed (i) Campbell units 1-3 would retire in 2025, but (ii) Karn units 3 and 3 would continue operating until 2031? If so, please identify each of those model runs (by Run ID as shown in workpaper WP-STW-1) and provide the NPV for each such run.

Response:

a. Yes, please see the Run IDs provided in the response to MEC-CE-044(b) and the corresponding NPVs found in Exhibit A-12 (STW-9). The Run IDs correspond to model runs that assumed acquisition of Covert in 2023 and <u>all</u> of Dearborn, Kalamazoo and Livingston in 2025. No model runs were performed for the 2021 IRP that assumed acquisition of a <u>smaller</u> subset of Dearborn, Kalamazoo and Livingston.

b. No, as my testimony, exhibits and workpapers demonstrate, no model runs were performed for the 2021 IRP that assumed acquisition of Covert in 2023 but excluded Dearborn, Kalamazoo and Livingston.

c. No, as my testimony, exhibits and workpapers demonstrate, no model runs were performed for the 2021 IRP with those retirement dates.

Sara T. Walz

Sara T Walz
August 18, 2021

Question:

13. For the Covert, DIG, Kalamazoo, and Livingston plants, please provide copies of any valuation estimates, whether conducted by Company personnel or third-party consultants.

Response:

The Company's decision to acquire the Covert, DIG, Kalamazoo, and Livingston plants was based on several internal and external economic evaluations of the assets. The Company ensured that selected plants were priced at a fair market value through the competitive solicitation process which utilized an independent third-party administrator (referred to as the "RFP Manager" in Company witness Troyer's direct testimony), benchmarking analyses, and modeling/rate analyses, as discussed in more detail below.

The Company initiated a Request for Proposal ("RFP") to be conducted by the RFP Manager to identify the potential size and cost of purchasing existing natural gas plants to be owned by the Company to: (i) satisfy a large capacity need in years 2023 and 2025 necessitated by the accelerated retirement of the coal units (Campbell Units 1, 2, and 3) and gas/oil fired peaking units (Karn Units 3 and 4) to enable the Company to be cleaner, faster, (ii) create savings for customers with the acceleration of those unit retirements, and (iii) lessen future market exposure for Consumers Energy's customers with an asset able to both minimize reliance on the market and serve Consumers Energy's customer's energy needs reliably. Additionally, the Company's retirement analysis selected a set of natural gas units in the Business As Usual scenario (i.e. the most likely scenario) indicating that the Company should explore the addition of natural gas resources. The appeal of existing natural gas fired units was a reduction in execution risk by avoiding construction while procuring proven natural gas generators, the ability to transition to natural gas faster (new construction would take 5 years), potential for lower cost than new gas construction, no additive air pollutant emissions to the State of Michigan, and no new incremental demand on the gas supply system.

As detailed beginning on page 52, line 11 of Company witness Troyer's direct testimony, the Company secured the services of Charles Rivers Associates ("CRA") to serve as an independent third party RFP Manager in order to meet FERC requirements for affiliate participation in the Request for Proposal. An RFP was created to satisfy potential capacity and energy needs by acquiring up to 2,000 MW of unforced capacity ("UCAP") between April 2023 and April 2026. In order to be considered in this RFP, generators were required to be existing natural gas-fueled combined cycle or combustion turbines located or transferrable to the Midcontinent Independent System Operator, Inc. ("MISO") Local Resource Zone 7 ("LRZ-7), with individual facilities sized between 50 and 1,400 MW (UCAP). The Company determined that 22 gas plants from 10 different owners would meet proposed eligibility criteria and therefore qualify to participate representing 6,269 MW of eligible installed capacity. CRA developed and scheduled the publication of a Consumers Energy RFP advertisement, which was run on January 8, 2021 within a daily issue of the S&P Global Platts Megawatt Daily publication. CRA proactively reached out to the 10 different owners with expected eligible generators and additionally to parties that have participated in other solicitations administered by CRA. Two prequalified entities submitted eligible bids encompassing a total of four generation facilities. Bids included two combined cycle facilities and two combustion turbine facilities. In total, the facilities bid into the RFP had approximately 2,000 MW of UCAP.

CRA reviewed all eligible proposals that met pre-determined qualifying criteria set forth in the RFP documentation and evaluated each based on certain pre-specified evaluation criteria. Generating assets offered into the RFP were evaluated based on: (i) estimated Net Present Value ("NPV") for the project over a 25-year period; (ii) asset age and reliability; and (iii) asset-specific benefits and risk factors. As provided as Exhibit A-49 (KGT-5) with my direct testimony, the Company received a recommendation from CRA on assets to advance for further due diligence by the Company. This resulted in the Company's selection of the bid including Covert Generating Facility ("Covert Plant") and the bid including the Dearborn Industrial Generation ("DIG Plant"), Kalamazoo River Generating Station ("Kalamazoo Plant"), and the Livingston Generating Station ("Livingston Plant") and the beginning of the Company's due diligence efforts on those bids. The NPV analyses for each project were developed by CRA using CRA's Aurora model to evaluate the economics of the project in the simulated wholesale market, instead of using simplistic excel-based calculations. CMS Enterprises submitted four proposal options with different combinations of the three assets. The highest ranked proposal (the only proposal that included the DIG Plant) included the acquisition of all three plants. The economic outcome for the Covert Plant and the DIG, Kalamazoo, and Livingston plants were a net positive (benefit) to customers. The NPVs for the Covert Plant and the DIG, Kalamazoo, and Livingston plants were $826,935/MW UCAP and $384,067/MW UCAP, respectively.

During the Company's due diligence efforts, the Company evaluated the bid prices against the cost of the construction of new natural gas plants (Combustion Turbine ("CT") and Combined Cycle ("CC")) and recent natural gas plant sales. Please see Confidential U21090-AG-CE-368-ATT1 and ATT2.

With respect to the cost of construction of new natural gas plants, the Company determined a CC estimate of $1200/kW to $1300/kW depending on the model/technology ($1200/kW for 600 MW H Class, $1300/kW for 400 MW F Class) and CT estimate of $750/kW. These costs are consistent with the Company's IRP modeling assumptions.

With respect to recent natural gas plant sales, the Company determined that, from 2008 to 2016, MISO CT plant sales averaged $260/kW, with an overall United States average of $200/kW to $400/kW, and MISO CC plant sales averaged $500/kW, with an overall United States average of $750/kW. These prices were based on IHS Energy's "US Conventional Power Plant Transactions" Report from October 2016. Overall market conditions and outlooks from 2016 compared to the time of this IRP have had varying offsetting factors influencing price (e.g., electric demand, capacity prices, energy prices) and therefore, the Company concluded that these were still relevant proxies to compare against. The Company also considered S&P Global Market Intelligence and determined that, for more recent power plant sales (2018 through 2020), CC transactions within MISO averaged $350/kW to $950/kW and CT transactions within MISO averaged $200/kW to $400/kW.

The proposed purchase cost of the DIG, Kalamazoo, and Livingston plants is at a price equal to $529/kW ($530 million/1001 MW). Even if that proposed purchase cost only included the DIG Plant, it would still be at a price equal to $688/kW ($530 million/770 MW) which indicates that the acquisition of the DIG Plant alone at the proposed purchase cost (for all three plants) would be within a reasonable range compared to other gas plant transactions. The proposed purchase cost of the Covert Plant is at a price equal to $693/kW ($815 million/1176 MW). The proposed purchase cost of the DIG, Kalamazoo, and

Livingston plants and the proposed purchase cost of the Covert Plant are approximately half of the cost of the construction of a new natural gas CC plant ($1200/kW to $1300/kW). The proposed purchase costs are also well within the range of recently sold natural gas CC plants (MISO average of $350/kW to $950/kW (2018 through 2020) and United States average of $750/kW from 2008 to 2016).

Furthermore, it should be noted that while the selected proposal including the DIG, Kalamazoo, and Livingston plants did not include pricing for the individual plants, the bidder did include separate proposals for the Kalamazoo and Livingston plants (as well as a proposal to acquire both Kalamazoo and Livingston) in the solicitation. The Kalamazoo Plant was bid separately for $23 million which equates to

$306/kW ($23 million/75 MW) and the Livingston Plant was bid separately for $29 million which equates to $186/kW ($29 million/156 MW). These prices are well under half the cost of the construction of a new natural gas CT plant ($750/kW) and well within the range of recently sold natural gas CT plants (MISO average of $200/kW to $400/kW (2018 through 2020) and United States average of $200/kW to 400/kW from 2008 to 2016).

The above benchmarking analysis establishes that the purchase cost of the Covert Plant and the purchase cost of the DIG, Kalamazoo, and Livingston plants represents the fair market value of those plants. Furthermore, it should be noted that the collective $/kW price of the DIG, Kalamazoo, and Livingston plants is at a lower cost than the Covert Plant, a non-affiliate plant. This further supports the purchase cost of the DIG, Kalamazoo, and Livingston plants and further demonstrates the purchase cost for those plants is a fair market price which benefits customers.

In addition to the benchmark analysis conducted by the Company, as described above, the Company also performed a modeling analysis which demonstrates that the Covert, DIG, Kalamazoo, and Livingston plants represent the least cost options for customers. The Company offered the Covert, DIG, Kalamazoo, and Livingston plants for economic selection in the model to replace Karn Units 3 and 4 in 2023 and Campbell Units 1, 2, and 3 in 2025 capacity and energy needs. The Aurora model selected the Covert Plant and the DIG, Kalamazoo, and Livingston plants as the “least cost” options to replace the retiring assets versus other resource types. The table below is a diagnostic report from Aurora providing a breakdown of $NPV/Zonal Resource Credit (“ZRC”) of each resource considered for selection. A greater positive NPV/ZRC amount indicates a more economic resource. The Covert Plant and the DIG, Kalamazoo, and Livingston plants combined are the highest NPV/ZRC and are therefore selected as the least cost option.

Resource Name	Begin Year	Selected	Capacity	NPV($000/ZRC)
New Resource 1655 from 616 New Covert Generating Facility (3)	2023	Yes	370.95	$ **1,454**
New Resource 1637 from 615 New Covert Generating Facility (2)	2023	Yes	370.95	$ **1,452**
New Resource 1709 from 619 New Covert Generating Facility (3A)	2023	Yes	19.94	$ **1,271**
New Resource 1673 from 617 New Covert Generating Facility (1A)	2023	Yes	19.94	$ **1,271**
New Resource 1691 from 618 New Covert Generating Facility (2A)	2023	Yes	19.94	$ **1,271**
New Resource 1441 from 599 CE New DR Tranche 1	2023	No	79.9	$ 1,121
New Resource 1619 from 614 New Covert Generating Facility (1)	2023	Yes	370.95	$ **212**
New Resource 1523 from 608 Dearborn Industrial Generation (ST1)	2025	Yes	193.46	$ **1,545**
New Resource 1491 from 606 Dearborn Industrial Generation (GT 1)	2025	Yes	193.46	$ **1,189**
New Resource 1507 from 607 Dearborn Industrial Generation (GT2)	2025	Yes	193.46	$ **1,188**
New Resource 1603 from 613 Kalamazoo River Generating Station	2025	Yes	72.99	$ **1,052**
New Resource 1587 from 612 Livingston Generating Station (004)	2025	Yes	30.72	$ **1,009**
New Resource 1555 from 610 Livingston Generating Station (002)	2025	Yes	30.72	$ **1,009**
New Resource 1571 from 611 Livingston Generating Station (003)	2025	Yes	30.72	$ **1,009**
New Resource 1539 from 609 Livingston Generating Station (001)	2025	Yes	30.72	$ **1,009**
New Resource 705 from 578 Storage ASM	2025	No	61.0411644	$ 1,005
New Resource 1443 from 599 CE New DR Tranche 1	2025	Yes	79.90	$ **998**
New Resource 1459 from 600 CE New DR Tranche 2	2025	Yes	10.90	$ **973**
New Resource 657 from 11 Utility-Scale Solar (Transmisson)	2025	Yes	42.58	$ **945**
New Resource 1393 from 602 CE New DR Tranche 4	2025	No	66.3	$ 922
New Resource 1409 from 603 CE New DR Tranche 5	2025	No	56.5	$ 897
New Resource 3 from 1 Combined Cycle "H" 2x1	2025	No	1234.25	$ 878
New Resource 721 from 580 Storage DAD	2025	No	2	$ 848
New Resource 689 from 16 Storage (Energy+Capacity)	2025	No	10000	$ 810
New Resource 154 from 5 Combustion Turbine "F" 1x0	2025	No	237	$ 797
New Resource 49 from 2 Combined Cycle "H" 1x1	2025	No	623.25	$ 781
New Resource 50 from 2 Combined Cycle "H" 1x1	2025	No	623.25	$ 781
New Resource 51 from 2 Combined Cycle "H" 1x1	2025	No	623.25	$ 781
New Resource 673 from 13 Utility-Scale Solar (Distribution)	2025	No	8000	$ 772
New Resource 1425 from 604 CE New DR Tranche 6	2025	No	255.4	$ 754
New Resource 97 from 3 Combined Cycle "F" 1x1	2025	No	390.5	$ 730
New Resource 305 from 6 RICE 5x0	2025	No	85	$ 627
New Resource 641 from 9 Out-State MI Wind	2025	No	10000	$ (363)
New Resource 625 from 7 Instate Wind	2025	No	10000	$ (396)
New Resource 1475 from 605 Dearborn Industrial Generation (GTP1)	2025	Yes	174.53	$ **(439)**

The above justifications of fair market value and the purchase of the gas units as least cost options supports the Company's economic evaluation of the PCA providing $600 to $650 million in customer savings versus the Alternate Plan, as represented by Company witness Blumenstock (Figure 16) based upon Company witness Coker's testimony and Exhibit A-36 (JRC-1).

Furthermore, with the accelerated retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3, as proposed by the Company in this IRP, the purchase of the Covert, DIG, Kalamazoo, and Livingston plants will meet an immediate capacity need by replacing approximately 2,200 MW of capacity over the next four years. The purchase of existing natural gas plants, as opposed to the construction of new natural gas plants, ensures the facilities are operational today and are not hindered by future risks to operational start dates and cost increases that a new resource build could have.

Jeffrey E. Battaglia

Jeffrey E. Battaglia
October 15, 2021

Enterprise Project Management

<u>Question:</u>

1. Referencing the table included on page 5 of the audit response "U21090-SACE-079":
a. Please identify the modeling run(s) that resulted in the selection of resources shown in this table, using the naming convention provided for other modeling runs included in this filing.
b. Were the resources identified in this table selected on an economic basis (e.g., as the least-cost resources in a LTCE modeling run)?
c. What Aurora project file was this run contained in?
d. On what date(s) were the modeling run(s) that provided the information in this table completed?

<u>Response:</u>

In development of its 2021 IRP, the Company did not create prototype resources for the Covert, Dearborn, Kalamazoo or Livingston units for selection in the long-term capacity expansion runs. The Company was highly confident the units <u>would be</u> selected, if offered, and therefore did not believe it was necessary to carry out the exercise. The Company believed this for the following primary reasons:

- The units were lower on a $/kW basis than all other prototype resources available for selection, which means the units would be likely to be selected ahead of all other available prototype resources,
- Higher-cost, new-construction natural gas resource had already been economically selected by the model under business as usual and CE natural gas assumptions,
- The RFP economic analysis performed by Charles River Associates indicated the units were economically favorable,
- The capacity needs in 2023 and 2025 were significant, with limited options available for selection that could deliver sufficient MW on such a short time horizon.

In fact, when the exercise was completed, in September of 2021 (during the discovery process, in which various parties in this case had issued questions regarding whether the units were selected by the model), the units were, indeed, economically selected by Aurora as the least-cost resources.

a. The modeling run used to develop the table provided in response to the referenced audit question is being provided to parties who have signed a non-disclosure agreement with Energy Exemplar and who have been granted temporary access to Aurora. The archived project file being shared is called "2021 IRP BAUCE PX 240_86" with the run ID "240_86_05_BAUCE_PX_STW_Test".

b. Yes. Aurora long-term capacity expansion options were utilized ("Limiting Resource ID") to ensure that the entirety of Covert (all six units modeled in Aurora) were required to be selected together. Likewise, the Dearborn, Kalamazoo and Livingston units were required to be selected as a bundle.

c. See the response to part (a).

d. The run was done on September 28, 2021.

Sara T. Walz

Sara T Walz
October 12, 2021

Electric Supply Planning

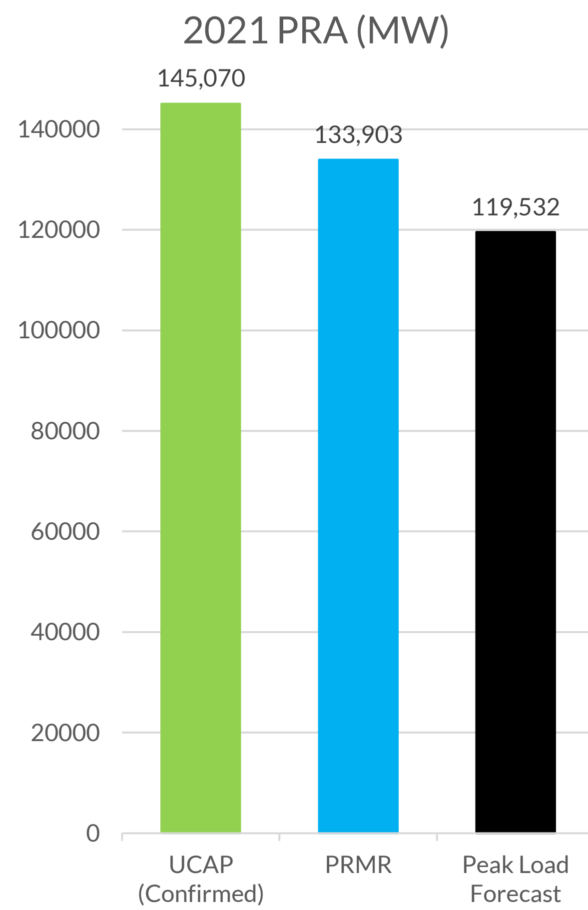
MISO

2021/2022 Planning Resource Auction (PRA) Results

April 15, 2021

MISO region has adequate reserves to meet its 134 GW Planning Reserve Requirement

- Zones 1-7 cleared at **$5.00**/MW-day, while Zones 8-10 cleared at **$0.01**/MW-day. Compared to last year, lower prices in Zones 7-10 are a result of a combination of lower peak demand or additional supply
- PRA enhancements implemented in the past year did not directly impact clearing prices
- Cleared capacity showed continued trend to non-conventional resources, which along with resource performance in tight conditions, is the basis for Reliability Imperative efforts
- Regional generation supply was consistent with the 2020 OMS-MISO Survey



MISO's RA construct combines regional and local criteria to achieve a least-cost solution for the region

Multiple options exist for Load-Serving Entities to demonstrate Resource Adequacy:

- Submit a Fixed Resource Adequacy Plan (FRAP)
- Utilize bilateral contracts with another resource owner
- Participate in the Planning Resource Auction (PRA)

The Independent Market Monitor (IMM) reviews the auction results for physical and economic withholding

Inputs

- Local Clearing Requirement (LCR) = capacity required from within each zone
- MISO-wide reserve margin requirements, which can be shared among the Zones, and Zones may import capacity to meet this requirement above LCR
- Capacity Import/Export Limits (CIL/CEL) = Zonal transmission limitations
- Sub-Regional contractual limitations such as between MISO's South and Central/North Regions

Outputs

- Commitment of capacity to the MISO region, including performance obligations
- Capacity price (ACP = Auction Clearing Price) for each Zone
- ACP price drives the settlements process
- Load pays the Auction Clearing Price for the Zone in which it is physically located
- Cleared capacity is paid the Auction Clearing Price for the Zone where it is physically located

Primary changes since 2020 Auction

Conventional Deliverable ICAP (ER20-1942)

FERC accepted a Tariff filing on October 27, 2020 to increase the deliverability requirements for Capacity Resources and related conversion of Capacity to Zonal Resource Credits ("ZRCs") in MISO's Planning Resource Auction. This filing addresses the deliverability and conversion rules applicable to conventional resources. In order to obtain full capacity credit, the resource must by fully deliverable.

Intermittent Deliverable ICAP (ER20-2005)

FERC accepted a Tariff filing on November 13, 2020 to increase the deliverability requirements for Capacity Resources and related conversion of Capacity to Zonal Resource Credits ("ZRCs") in MISO's Planning Resource Auction. Amount of capacity eligible to be converted into ZRCs depends on the performance and deliverability level of the intermittent resource.

Annual CIL/CEL Study's Voltage Stability Analysis Methodology (LOLEWG)

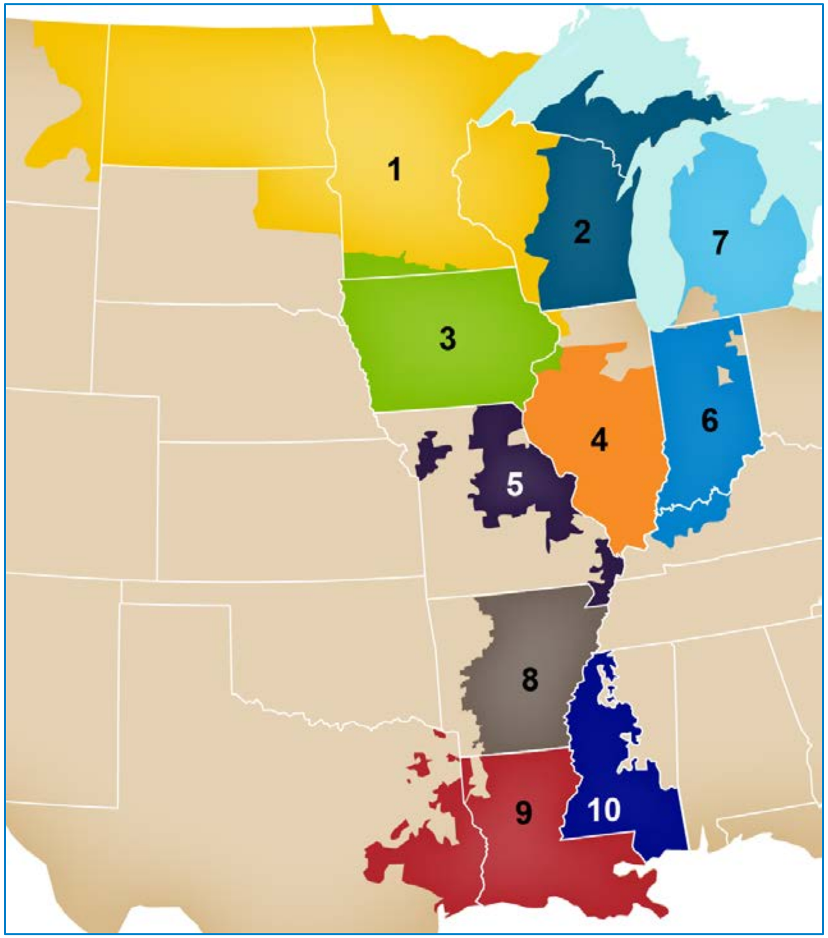
CIL/CEL studies utilize generator to generator transfers, however Zonal imports may be limited by voltage constraints. For additional voltage analyses , the PY 21/22 transfer utilizes a gen-gen transfer methodology, whereas the previous PY utilized a load-load transfer method. Gen to Gen transfer is more reflective of system capability at peak hour.

Ongoing Fleet Change

The auction results reflect the industry's ongoing shift away from coal-fired generation and increasing reliance on gas-fired resources and renewables, as well as other trends discussed in our MISO Forward report.

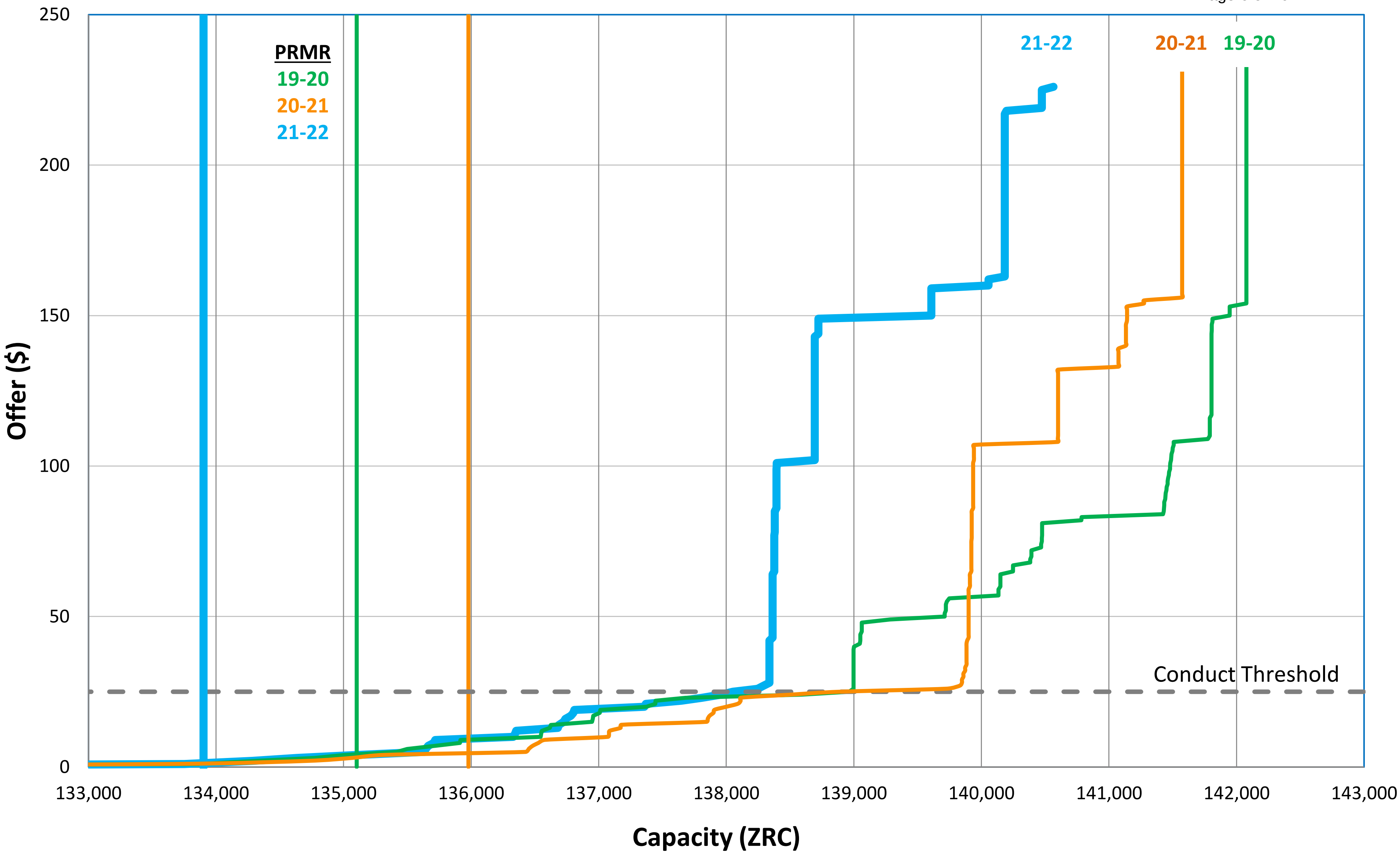
South to North capacity transfer limit reached causing price separation of $4.99

Zone	Local Balancing Authorities	Price $/MW-Day
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	$5.00
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	$5.00
3	ALTW, MEC, MPW	$5.00
4	AMIL, CWLP, SIPC, GLH	$5.00
5	AMMO, CWLD	$5.00
6	BREC, CIN, HE, IPL, NIPS, SIGE	$5.00
7	CONS, DECO	$5.00
8	EAI	$0.01
9	CLEC, EES, LAFA, LAGN, LEPA	$0.01
10	EMBA, SME	$0.01
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$2.78-5.00



ERZ = External Resource Zones

2021-22 Offer Curve



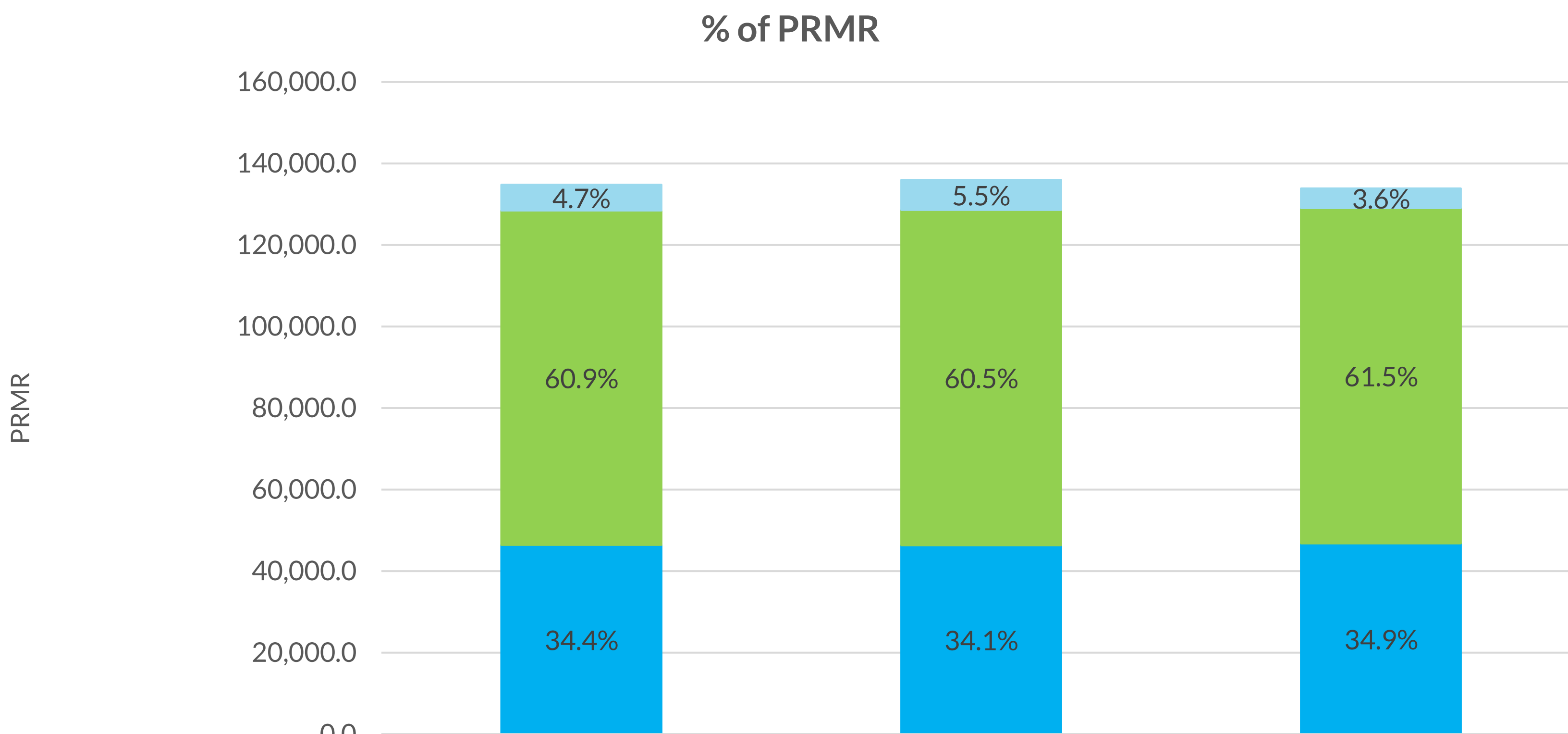
2021/22 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,359.0	13,616.5	10,279.5	9,852.5	8,246.8	18,145.8	21,459.2	7,827.8	21,282.6	4,833.0	N/A	133,902.7
Offer Submitted (Including FRAP)	20,289.3	13,979.9	10,826.7	9,506.1	7,811.4	15,832.2	21,666.3	10,642.5	23,017.4	5,353.8	1,639.4	140,565.0
FRAP	14,408.1	11,657.8	4,159.9	669.0	0.0	1,519.7	12,186.4	513.5	174.7	1,374.2	94.1	46,757.4
Self Scheduled (SS)	3,507.4	2,290.3	6,097.5	6,327.8	7,811.4	12,519.4	9,295.5	9,299.4	20,151.5	3,591.7	1,395.0	82,286.9
Non-SS Offer Cleared	772.0	0.0	454.3	1,335.2	0.0	1,706.8	67.5	116.6	308.1	0.0	97.9	4,858.4
Committed (Offer Cleared + FRAP)	18,687.5	13,948.1	10,711.7	8,332.0	7,811.4	15,745.9	21,549.4	9,929.5	20,634.3	4,965.9	1,587.0	133,902.7
LCR	14,875.1	10,670.0	6,713.7	6,450.4	5,282.8	12,166.3	19,710.1	4,988.4	19,404.2	3,632.8	-	N/A
CIL	5,061	3,599	4,620	NLF*	4,384	7,138	4,888	5,203	4,096	3,283	-	N/A
ZIA	5059	3599	4556	5141	4384	6738	4888	5155	3284	3283	-	N/A
Import	0.0	0.0	0.0	1,520.5	435.4	2,399.9	0.0	0.0	648.3	0.0	-	5,004.1
CEL	2,474.0	3,488.0	NLF*	4,912.0	NLF*	4,595.0	NLF*	NLF*	1,978.0	1,369.0	1,452.2	N/A
Export	328.5	331.6	432.2	0.0	0.0	0.0	90.2	2,101.7	0.0	132.9	1,587.0	5,004.1
ACP ($/MW-Day)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	0.01	0.01	0.01	2.78 to 5.00	N/A

Values displayed in MW UCAP *NLF = No Limit Found: Tier 1 & 2 source capacity is less than the study transfer limit

MISO

Members continue to use FRAP and Self Schedule to meet Resource Adequacy Requirements



	19-20	20-21	21-22
Cleared Non-Self Scheduled	6,281.9	7,419.1	4,858.4
Self Scheduled	82,046.9	82,240.0	82,286.9
FRAP	46,414.2	46,320.2	46,757.4

Historical Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-
$5.00</td></tr>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-
$5.00</td></tr>
</table>

IMM Conduct Threshold	25.43	24.92	23.92	24.86	26.67	24.42	25.97	23.09	22.90	22.86	26.67
Cost of New Entry	254.27	249.15	239.21	248.55	266.68	244.16	259.73	230.93	229.04	228.55	266.68

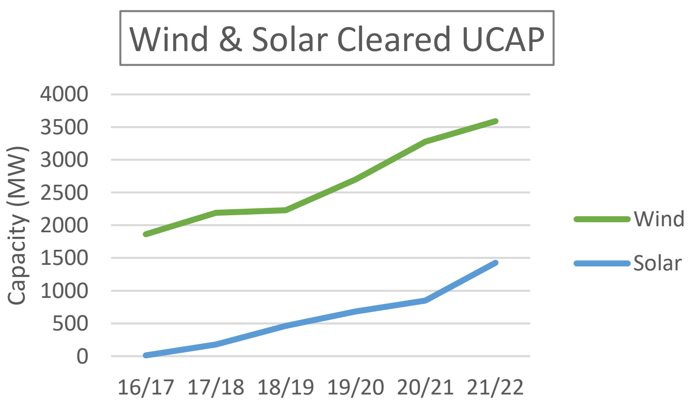
- Auction Clearing Prices shown in $/MW-day
- Conduct Threshold is 10% of Cost of New Entry (CONE)

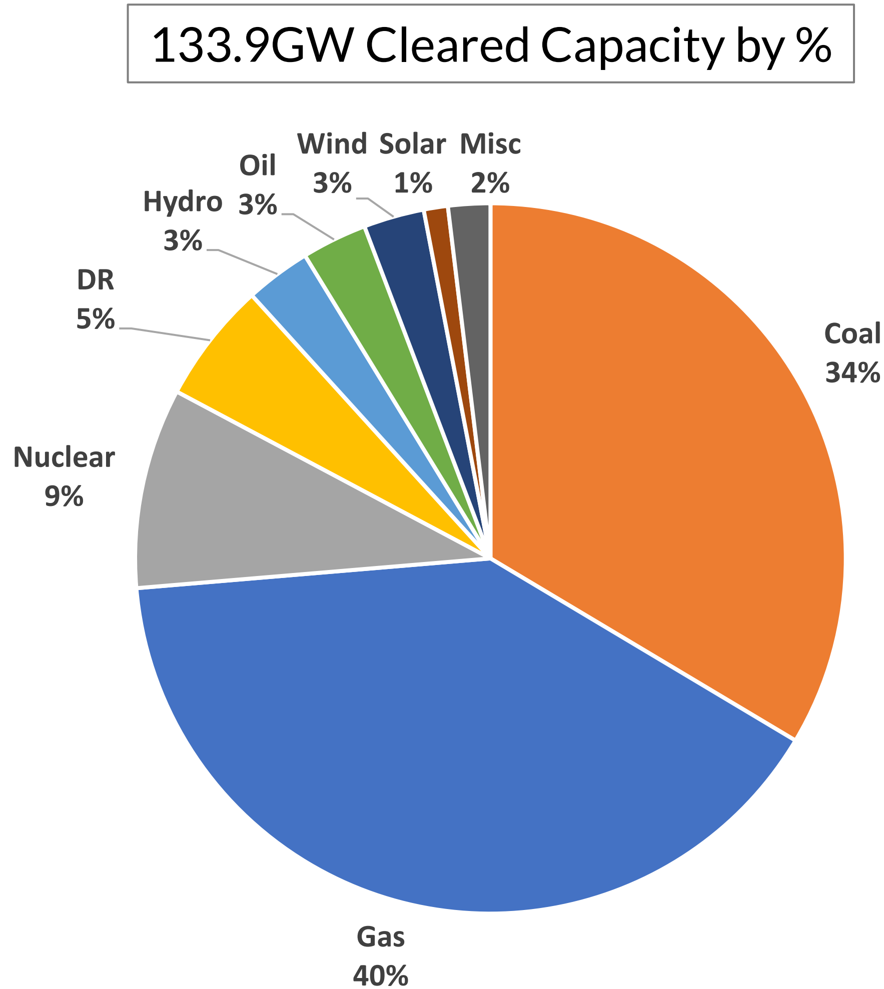
Supply Offered & Cleared

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**2019-20**	**2020-21**	**2021-22**	**2019-20**	**2020-21**	**2021-22**
Generation	125,290	125,341	125,225	119,779	120,143	118,884
External Resources	4,402	3,832	3,914	3,183	3,736	3,798
Behind the Meter Generation	4,202	3,997	4,131	4,097	3,892	4,068
Demand Resources	7,876	7,754	7,294	7,372	7,557	7,152
Energy Efficiency	312	650	0	312	650	0
Total	**142,082**	**141,574**	**140,564**	**134,743**	**135,979**	**133,903**

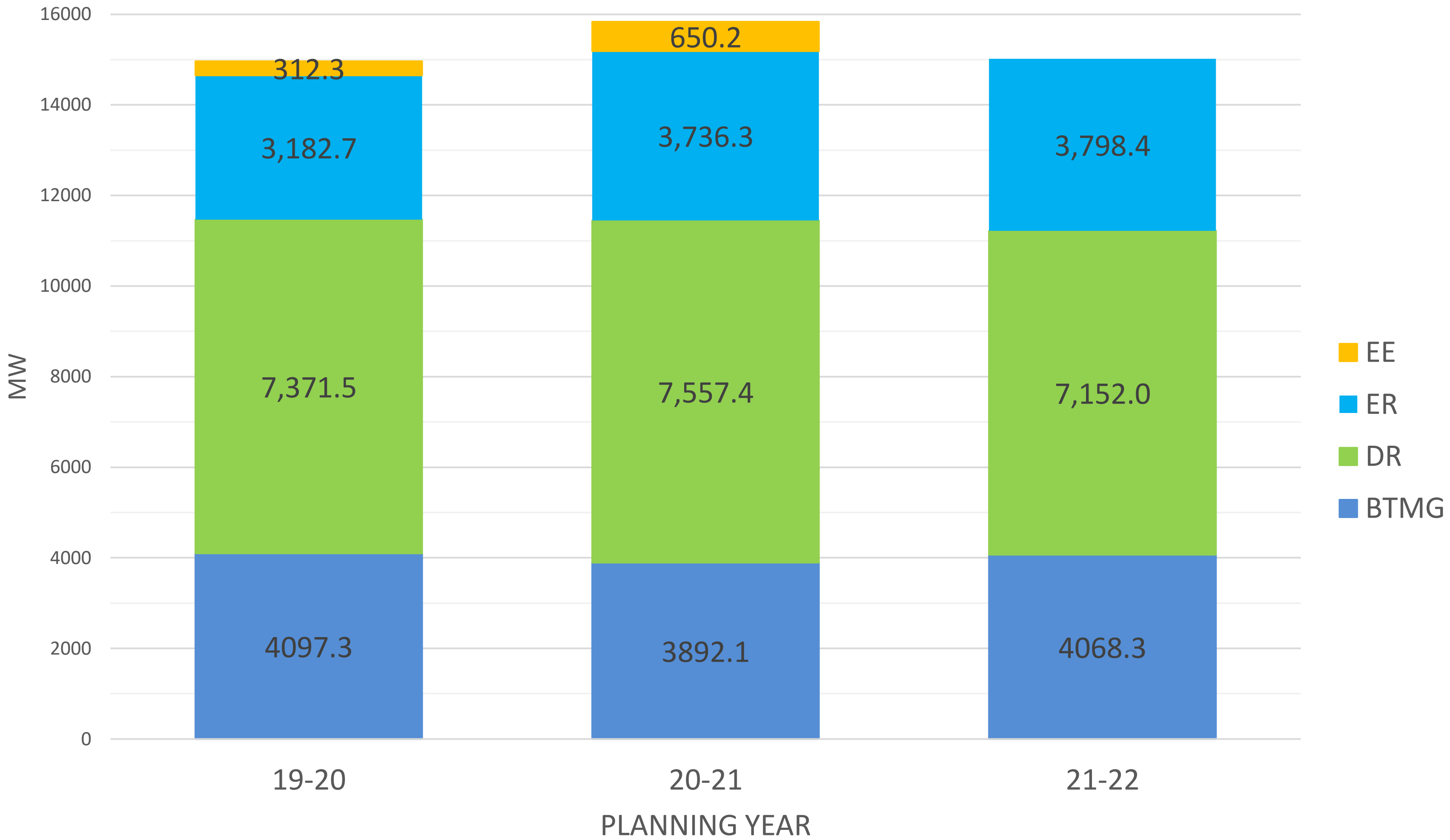
Conventional generation provides majority of capacity, while wind and solar continue to grow

- 1,426 MW of solar cleared this year's auction—an increase of 68% from PY 2020-21 (850 MW).
- Similarly, 3,590 MW of wind cleared this year, an increase of 10% compared to last year (3,275 MW).

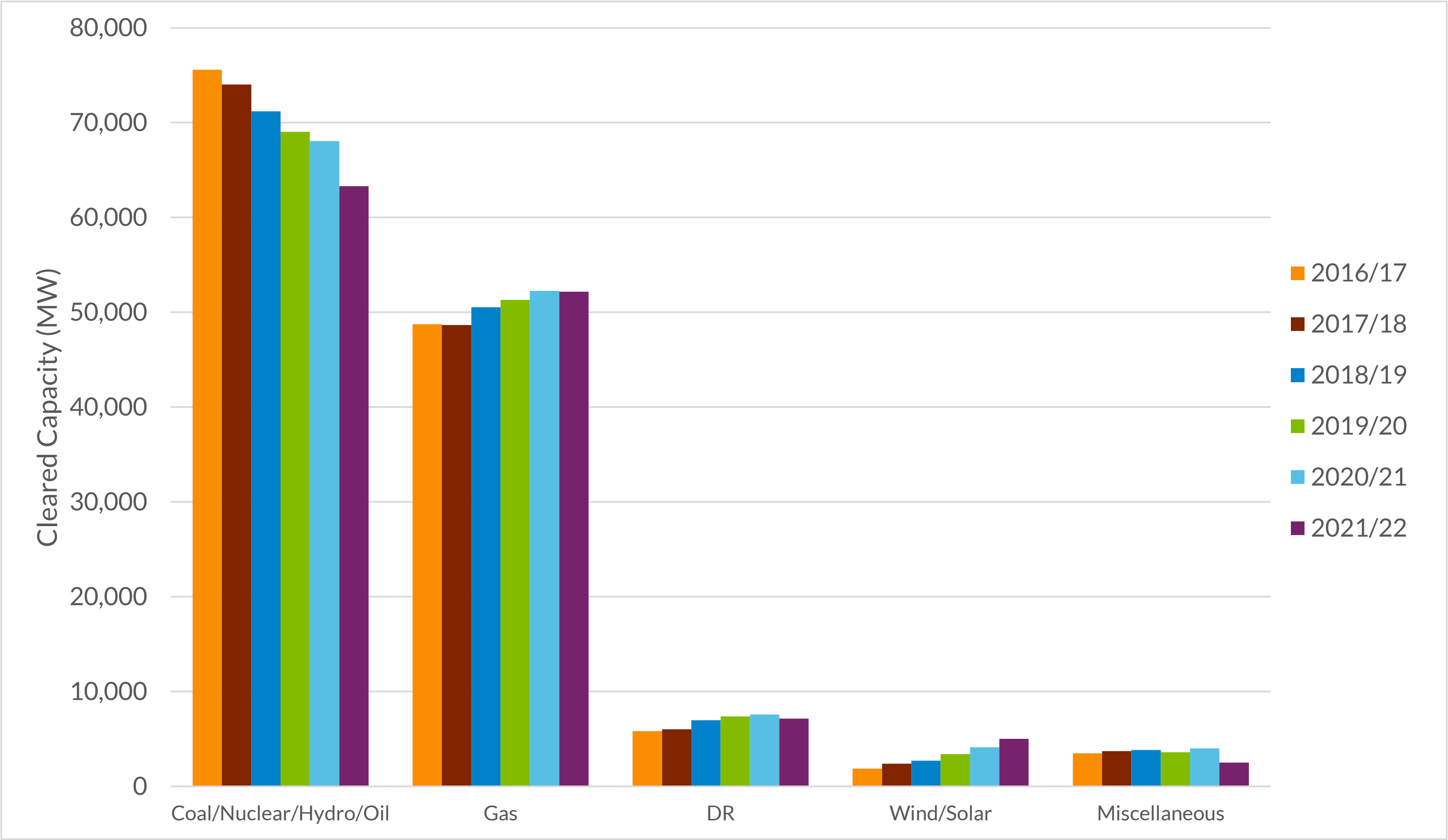




Demand-based resources declined due to lack of qualified Energy Efficiency



Planning resource mix continues the multi-year trend of less solid fuel and increased gas and non-conventional



Next Steps

- **APR 15** – Conference call presentation of PRA results
- **MAY 12** – Zonal Deliverability Benefits and additional PRA analytics at the May RASC
- **MAY 14** – Posting of PRA masked offer data
- **MAY 25** – MISO published cleared LMRs to the MCS
- **MAY 28** – MPs submit ICAP and DR Testing Deferral info
- **JUN 1** – New Planning Year starts

Appendix

Acronyms

ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
DR: Demand Resource
EE: Energy Efficiency
ER: External Resource
ERZ: External Resource Zones
FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor
LCR: Local Clearing Requirement
LMR: Load Modifying Resource
LRZ: Local Resource Zone
LSE: Load Serving Entity
PRA: Planning Resource Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
SS: Self Schedule
SFT: Simultaneous Feasibility Test
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

RAdequacy@misoenergy.org

Resource	2021 ZRC	2022 ZRC	2023 ZRC	2024 ZRC	2025 ZRC
Campbell 1	240	242.8	243.6	251.5	250.9
Campbell 2	310.6	318.9	328	329.1	328.5
Campbell 3	755.2	744.4	758.8	754.1	759.5
Karn 1	219.2	215.5			
Karn 2	202.3	200.1			
Estimated capacity value $/day	**2021 Capacity Value**	**2022 Capacity Value**	**2023 Capacity Value**	**2024 Capacity Value**	**2025 Capacity Value**
Campbell 1	$46,751	$48,242	$49,369	$51,989	$52,903
Campbell 2	$60,503	$63,362	$66,474	$68,031	$69,265
Campbell 3	$147,109	$147,905	$153,782	$155,886	$160,142
Karn 1	$42,699	$42,818			
Karn 2	$39,407	$39,758			
PRA actuals					
2019 PRA $/MW-day	24.3				
2020 PRA $/MW-day	257.53				
Forecasted value: 75 % of CONE					
2021 $/MW-day	194.8				
2022 $/MW-day	198.7				
2023 $/MW-day	202.7				
2024 $/MW-day	206.7				
2025 $/MW-day	210.9				

Year	PRA Results	MISO CONE	% of CONE Forecasted	Planning Year Annual Value		MISO CONE Assumptions	Value	Unit
						CT size	237	MW
2012				62		% Debt	55	%
2013	1.050	99,310		383		Project Life	20	Yr
2014	16.750	90,100		6,114		Debt Interest Rate	5.2	%
2015	3.480	90,530		1,270		O&M Escalation	2.0	%
2016	72.000	94,830	75%	26,280		GDP Deflator	2.0	%
2017	1.500	94,900	75%	548		Fed/State Tax	25 to 33	%
2018	10.000	90,740	75%	3,650		Property Tax & Insu	1.5	% of Capital
2019	24.300	88,830	75%	8,870		WACC	7.96 to 8.19	%
2020	257.530	94,000	75%	93,998		After-Tax ROE	13.4	%
2021		94,800	75%	71,100		Capital Cost	779.0	$/kW
2022		96,696	75%	72,522		MISO Zone 7 CONE	94,800	$/MW-Year
2023		98,630	75%	73,972				
2024		100,603	75%	75,452				
2025		102,615	75%	76,961				

75% CONE - Annual Capacity Prices Based on Cost of New CT 2021+
(MISO PRA Actuals Through May 2021)

Year	Planning Year Annual Value	Calendar Year Annual Value	January	February	March	April	May	June	July	August	September	October	November	December
			31	28	31	30	31	30	31	31	30	31	30	31
	($/MW-yr)	($/MW-yr)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)
2010	33.94	31.20	0.25	0.25	0.50	0.35	0.35	5.00	10.00	10.00	3.00	0.25	0.25	1.00
2011	2.25	5.95	2.50	0.94	0.50	0.25	0.25	0.35	0.50	0.28	0.25	0.01	0.02	0.10
2012	61.57	61.62	0.20	0.19	0.10	0.10	0.15	0.40	50.00	10.00	0.15	0.14	0.10	0.09
2013	383.25	225.39	0.19	0.15	0.10	0.10	0.15	31.50	32.55	32.55	31.50	32.55	31.50	32.55
2014	6113.75	3743.05	32.55	29.40	32.55	31.50	32.55	502.50	519.25	519.25	502.50	519.25	502.50	519.25
2015	1270.20	3273.97	519.25	469.00	519.25	502.50	519.25	104.40	107.88	107.88	104.40	107.88	104.40	107.88
2016	26280.00	15933.48	107.88	97.44	107.88	104.40	107.88	2160.00	2232.00	2232.00	2160.00	2232.00	2160.00	2232.00
2017	547.50	11193.00	2232.00	2016.00	2232.00	2160.00	2232.00	45.00	46.50	46.50	45.00	46.50	45.00	46.50
2018	3650.00	2366.50	46.50	42.00	46.50	45.00	46.50	300.00	310.00	310.00	300.00	310.00	300.00	310.00
2019	8869.50	6710.20	310.00	280.00	310.00	300.00	310.00	729.00	753.30	753.30	729.00	753.30	729.00	753.30
2020	93998.45	58780.72	753.30	680.40	753.30	729.00	753.30	7725.90	7983.43	7983.43	7725.90	7983.43	7725.90	7983.43
2021	71100.00	80573.06	7983.43	7210.84	7983.43	7725.90	7983.43	5843.84	6038.63	6038.63	5843.84	6038.63	5843.84	6038.63
2022	72522.00	71933.72	6038.63	5454.25	6038.63	5843.84	6038.63	5960.71	6159.40	6159.40	5960.71	6159.40	5960.71	6159.40
2023	73972.44	73372.39	6159.40	5563.33	6159.40	5960.71	6159.40	6079.93	6282.59	6282.59	6079.93	6282.59	6079.93	6282.59
2024	75451.89	74839.84	6282.59	5674.60	6282.59	6079.93	6282.59	6201.53	6408.24	6408.24	6201.53	6408.24	6201.53	6408.24
2025	76960.93	76336.64	6408.24	5788.09	6408.24	6201.53	6408.24	6325.56	6536.41	6536.41	6325.56	6536.41	6325.56	6536.41

filled cells represent forecasted months

Question:

2. Refer to Table 2, and to page 14, line 14 through page 15, line 2 of the Hugo Direct Testimony.

   a. Please explain why you would calculate the capacity value of the Company's generating units based upon CONE, rather than using (i) the settlement price reflected in the MISO Planning Resource Auction, or (ii) the estimated cost of acquiring replacement capacity.
   b. Please identify the capacity value for each of the Company's coal units for each of the years 2014-2019. (Please provide the projected capacity value in dollars for any portion of 2019 where actual figures are not yet available.)
   c. Please provide the Company's most up-to-date projection of each of the coal units' capacity value in dollars for each of the years 2020-22, including supporting assumptions for those values.

Response:

a. Table 2 includes calculations of the generating unit capacity values based upon both the Zone 7 settlement price reflected in the PRA as well as CONE. Both calculations were conducted to provide a range of reasonable values for the capacity of each generating unit. A calculation using the estimated cost of acquiring replacement energy was not performed because the Company currently has sufficient capacity.

b. See Attachment U20697-MEC-CE-033_ATT_1. All of the values are based upon ZRC values and PRA settlement price. The capacity values are based upon the following settlement prices per ZRC-year:

2014	6,114
2015	1,270
2016	26,280
2017	548
2018	3,650
2019	8,870

c. See Attachment U20697-MEC-CE-033_ATT_1. The projected capacity value is based on 75% of MISO's CONE filing from September 2019 ($94k/ZRC-yr). The Company projects a capacity price at 75% of CONE based on the premise that if Zone 7 was short on capacity, the capacity prices would hit CONE for 3 years and by year 4 a new resource would be available.

2020	70,500
2021	71,910
2022	73,348

Scott A. Hugo
April 6, 2020

Director – Generation Asset Strategy

MEC-28C

CONFIDENTIAL EXHIBIT

BEFORE THE
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

In the Matter of Monongahela Power Company and the Potomac Edison Company Petition for Approval of a Generation Resource Transaction and Related Relief	Case No. 17-0296-E-PC

Direct Testimony of
Tyler Comings

On Behalf of
Sierra Club

PUBLIC TESTIMONY

August 25, 2017

Table of Contents

Table of Figures

without the transaction, not counting the potential cost to ratepayers with the transaction.

Q If the transaction were to cost ratepayers instead of save them money, could it have a negative economic impact on West Virginia?

A Yes. Dr. Deskin's analysis estimates the economic impact of the plant's operations, not its impact on ratepayers' bottom line. If the Companies' ratepayers were paying more for electric service because of this transaction, then: 1) residents would have less to spend elsewhere in West Virginia's economy, and 2) businesses would become less competitive due to higher electricity rates. These effects could produce a negative economic impact on West Virginia due to the transaction.

7. THE RFP PROCESS WAS BIASED TOWARDS THE PLEASANTS PLANT

Q What key provisions did the Companies set in the RFP for generating assets?

A The Companies required that generating asset would be: 1) located in the PJM APS zone, 2) dispatchable, 3) sold 100 percent to the Companies (no partial ownership or PPAs).

Q Did these criteria severely limit competition in the RFP process?

A Certainly. The Companies' requirements ruled out purchase power agreements (PPAs), partial ownership, intermittent resources such as solar or wind, or resources in PJM but not in the APS zone. Allowing for these options would open up a much larger pool of competition and a lower-cost option for ratepayers. However, because these options were prevented by the Companies, we will never know. Two of the bids for PPAs were not evaluated because they did not conform to the Companies' criteria. However, this does not include other assets or PPAs that would have bid in if the criteria were more relaxed.

Q Were the Companies' criteria necessary to provide reliability to their service territory?

A No. The Companies are subject to PJM rules for providing capacity to their territory. PJM determines the Companies' capacity obligation and what of their capacity counts towards that obligation. Under these rules, the Companies could pursue partial ownership or a PPA for a plant outside of the APS zone—or a 100 percent ownership of a plant outside that zone. It could also pursue a non-dispatchable asset or assets such as wind or solar. Instead, the Companies have placed unnecessary restrictions on themselves by dismissing these myriad options.

Q Was the timing sufficient for bidders to respond?

A No. The bidders only had one week to prequalify.[49] The Companies claim that they did not receive complaints about this timeframe but, again, that is based on the limited set of bids received due to the restrictive nature of the RFP.

Q Was the Companies' RFP biased towards the acquisition of Pleasants?

A It appears so. The Companies set up unnecessarily stringent criteria and an extremely short timeframe for the RFP that effectively limited the competition. Ultimately, only three bids were evaluated—including Pleasants. Even if the Companies had a capacity need, that need could be filled by a PPA, partial ownership of a plant, a plant or PPA outside of the PJM APS zone, and a non-dispatchable resource. However, all of these options were excluded from consideration, thus severely limiting options for ratepayers.

8. Findings and Recommendations

Q What are your key findings?

A My key findings include the following:

- **The Companies do not need Pleasants for capacity.** The Companies' argument that there is a winter capacity shortfall is a "red herring." The

[49] Companies RFP, p.8.

MEC-30C

CONFIDENTIAL EXHIBIT

MEC-31C

CONFIDENTIAL EXHIBIT

MEC-32C

CONFIDENTIAL EXHIBIT

Question:

32. Refer to the Kvoriak Direct Testimony, page 3, line 12 through page 4, line 13.
a. Please confirm that, under the current law (as of today), a wind farm that starts operation in 2025 could receive 60 percent of the production tax credit (PTC).
i. If confirmed, please explain why the Company did not apply a PTC for wind resources starting operation in 2025.
ii. If not confirmed, please explain why not.
b. Further refer to page 7, lines 14-15, which states that it is "likely that the PTC and ITC will be extended." Please confirm that the Company has not modeled any extensions of the PTC or ITC, beyond current law, in this IRP .
i. If confirmed, please explain why the Company did not apply a PTC for wind resources starting operation in 2025.
ii. If not confirmed, please explain why not.

Response:

a. Under current law, as of today, a wind farm that starts operation in 2025 could receive 60 percent of the production tax credit. The Company did not apply a production tax credit for wind resources starting operation in 2025 because this was not the law at the time the Company performed its resource modeling.

b. The Company did not model any extensions of the PTC or ITC beyond the law in force at the time the Company performed its resource modeling in this IRP.

Carolee Kvoriak
August 20, 2021

Corporate Tax

MEC-34C

CONFIDENTIAL EXHIBIT

Question:

24. For each of the Covert and CMS gas units, please provide the following information for 2016-2020 (inclusive) in Excel format, on an annual basis:
a. random outage rate (%)
b. periodic factor (%)
c. availability (%)
d. heat rate (Btu/kWh)
e. capacity factor (%)
f. Zonal Resource Credits (ZRCs)
g. net generation (in MWh)
h. capital expenditures
i. O&M expenses
j. total fuel cost
k. total fuel usage (in MMBtu)
l. equivalent availability factor
m. effective planned outage rate
n. effective forced outage rate
o. summer net demonstrated capacity
p. energy revenue

Note: if the Company does not have unit-level information for a particular cost category, please provide the most disaggregated data available

Response:

Please see attachments U21090-MEC-CE-058_ATT_1 and U21090-MEC-CE-058_ATT_2 which contains the currently available operational data. These attachments were provided to the Company through the RFP process from Segreto Power Holdings and CMS Enterprises as Appendix E to the RFP response. The following additional capacity factor information for 2016 and 2017 has been received from CMS Enterprises.

2016
DIG – 74.9%
Kalamazoo – 0.69%
Livingston – 0.26%

2017
DIG – 68.8%
Kalamazoo – 0.58%
Livingston – 1.08%

Below is the energy revenue for Covert as provided in the RFP response:

	History		
	2018	**2019**	**2020**
Energy Revenue	$ 219,517	189,895	151,482
Delivered Fuel Cost	(151,230)	(132,931)	(102,610)
Net Energy Margin	68,287	56,965	48,872
PJM Capacity Revenue	59,515	48,132	32,603
Reactive Power Revenue	1,900	1,900	1,900
Other Ancillary Services Revenue	263	209	855
Total Revenue (Net of Fuel Cost) ($000s)	**$ 129,965**	**$ 107,205**	**$ 84,230**

Below is the energy revenue/fuel costs for the CMS units as provided in the RFP response:

KALAMAZOO	2018	2019	2020
Revenue			
Electric Sales-Energy Revenue - Capacity	1,647,260	1,409,089	1,805,600
Electric Sales-Energy Revenue - Fixed	-	1,183,200	1,153,200
Electric Sales-Energy Revenue - Demand	-	3,234,520	4,519,458
Electric Sales-Energy Revenue - MISO	835,827	330,889	288,794
Electric Sales-Reactive Power Revenue	162,376	150,760	148,624
Other Income	-	-	-
Total Revenues	2,645,463	6,308,458	7,915,676
Cost of Sales			
Fuel	422,472	1,814,532	1,715,059
MISO Purchases	-	1,294,535	2,856,179
Fuel Transportation	-	85,166	82,729
Monthly Service Charge	225,726	(10,577)	46,726
Standby Service Charge	-	-	-
Total Fuel Expenses	648,198	3,183,657	4,700,693
Gross Margin	**1,997,265**	**3,124,801**	**3,214,984**

OPERATING COSTS & REVENUES

DEARBORN INDUSTRIAL GENERATION	2018	2019	2020	2021	2022	2023
Revenue						
Power Sales:						
AK Steel	6,800,050	6,247,162	6,264,292	6,885,360	6,885,360	6,885,360
Energy Fee	37,795,916	51,518,900	51,526,100	51,572,400	51,572,400	51,572,400
Capacity	18,119,327	15,782,876	20,231,424	21,756,233	23,343,479	26,140,092
Tolling - I/C	0	0	0	0	0	0
Merchant Energy	147,946,156	118,728,317	98,061,327	131,717,612	124,624,550	119,678,084
Reactive Power	1,971,090	1,812,978	1,758,878	1,900,000	1,900,000	1,900,000
Other Energy Sales	0	0	0	0	0	0
Total Power Sales	212,632,539	194,090,233	177,842,021	213,831,605	208,325,789	206,175,936
Steam Sales	12,343,524	13,347,536	11,250,195	11,941,033	12,299,264	12,668,242
Michigan Gas Production	0	0	0	0	0	0
DIG Storage	0	0	0	0	0	0
Other Income	8,398	16,627,615	284,876	66,000	0	0
Gross Revenue	224,984,461	224,065,384	189,377,092	225,838,638	220,625,053	218,844,178
Cost of Sales						
Fuel Burned for Generation	103,710,989	96,779,184	70,393,991	103,542,596	100,564,974	88,520,548
NG Purchased from Producers	0	0	0	0	0	0
Blast Furnace Gas	12,968,288	14,772,671	10,459,411	14,253,089	14,680,681	15,121,102
External Power Purchases	25,770,682	25,621,947	34,576,750	25,990,094	21,487,400	36,206,542
ROA/Transmission/Ancillary	72,926	67,955	47,394	180,000	180,000	180,000
Gas Transportation Charges	3,979,184	4,562,206	5,311,091	6,321,001	7,251,359	6,830,496
Major Maintenance (LTSA)	10,930,494	12,046,573	11,420,898	13,358,800	14,489,300	13,080,900
Total Cost of Sales	157,432,564	153,850,537	132,209,535	163,645,579	158,653,715	159,939,587
Gross Margin	**67,551,897**	**70,214,847**	**57,167,557**	**62,193,059**	**61,971,338**	**58,904,592**

LIVINGSTON	2018	2019	2020
Revenue			
Electric Sales-Energy Revenue - Capacity	3,294,519	2,818,177	3,629,810
Electric Sales-Energy Revenue - Fixed	-	-	-
Electric Sales-Energy Revenue - Demand	-	-	-
Electric Sales-Energy Revenue - MISO	578,783	761,544	257,121
Electric Sales-Reactive Power Revenue	324,750	301,519	297,247
Other Income	-	-	-
Total Revenues	4,198,052	3,881,241	4,184,178
Fuel Expense			
Fuel	253,380	493,054	142,536
MISO Purchases	-	-	1,864
Fuel Transportation	-	-	-
Monthly Service Charge	113,810	197,037	118,122
Standby Service Charge	189,700	243,900	216,800
Total Fuel Expenses	556,889	933,991	479,322
Gross Margin	**3,641,163**	**2,947,250**	**3,704,856**

Below is the UCAP (ZRCs) for the CMS units as provided in the RFP response.

MISO UCAP

Please find below the UCAP award to each Facility for the four most recent MISO Planning Years and the projected UCAP for the next three Planning Years.

Planning Year	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
DIG							
DECO.DIGG1	161	158	159	162	161	161	161
DECO.DIGG2	169	165	167	167	167	167	167
DECO.DIGG3	167	166	167	160	161	161	161
DECO.DIGS2	71	71	70	71	70	70	70
DECO.DIGS3	71	71	70	71	70	70	70
DECO.DIGSINT	98	97	96	97	99	99	99
	736	**727**	**729**	**729**	**728**	**728**	**728**
KRGS							
CONS.KAL_RGEN_	**69**	**67**	**71**	**74**	**70**	**70**	**70**
LGS							
CONS.LIVINGEN1	32	32	32	29	29	29	29
CONS.LIVINGEN2	30	32	32	30	30	30	30
CONS.LIVINGEN3	31	31	32	30	30	30	30
CONS.LIVINGEN4	32	32	32	31	25	25	25
	125	**126**	**127**	**120**	**114**	**114**	**114**

Norman J. Kapala
August 20, 2021

Executive Director – Fossil and Renewable Generation

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

					Historic	Budgeted/Forecasted		
		2016	2017	2018	2019	2020	2021	2022	2023

5.4: Net Capability of Generating Facility

Nameplate Capacity (MW)						770.0
	Jan	Feb	Mar	Apr	May	Jun
Net Monthly Capability (MW)	790.0	790.0	765.0	760.0	750.0	725.0
	Jul	Aug	Sep	Oct	Nov	Dec
	720.0	720.0	745.0	750.0	755.0	790.0

5.6: Generation Technology

Unit 1 - 7FA GE gas turbine
Unit 2 & 3 - 7FA GE gas turbines each with HRSG
Unit 4 - Alstom Steam Turbine Generator - fed by the two HRSGs and three auxilliary boilers

5.7: MISO UCAP

	2016	2017	2018	2019	2020	2021	2022	2023
UCAP (MW)	-	-	736.0	727.0	729.0	728.0	728.0	728.0

5.8: Heat Rates and Emission Rates

	Constant	x	x^2	x^3	x^4	x^5
Heat Rate Curve						

No Load Cost ($/hour)	
Avg Minimum Load Heat Rate (MMBtu/MWh)	
Incremental Heat Rates (MMBtu/MWh) at:	
50% of Full Load	
75% of Full Load	
Avg Full Load Heat Rate (MMBtu/MWh)	7200, 7500, 9500, 14000
Incremental Duct Firing Heat Rate (MMBtu/MWh)	n/a
NOx (lb/MMBtu)	9ppm, 9ppm, 0.10lb/MMBtu
SO_2 (lb/MMBtu)	n/a
CO_2 (lb/MMBtu)	n/a
VOC (lb/MMBtu)	2.8 pph, 26pph, 7.5pph (all monthly avg.)
PM (lb/MMBtu)	9pph,9pph, 22.3pph (
CO (lb/MMBtu)	30pph,31pph,64.1 pph

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

		2016	2017	2018	2019	2020	2021	2022	2023
						Historic	Budgeted/Forecasted		
5.9: Operating Costs and Revenues				2018	2019	2020	2021	2022	2023
Variable, non-fuel O&M Cost (excluding LTSA) ($K)				$73.00	$68.00	$47.00	$180.00	$180.00	$180.00
Variable LTSA Related O&M Cost ($K)				$10,931.00	$12,047.00	$11,421.00	$13,359.00	$14,489.00	$13,081.00
Delivered Fuel Costs ($K)				$146,429.00	$141,736.00	$120,741.00	$150,107.00	$143,984.00	$146,679.00
Fixed O&M Costs (excluding LTSA) ($K)				$19,557.00	$19,570.00	$16,401.00	$17,092.00	$16,332.00	$22,566.00
Fixed LTSA Related O&M Cost ($K)				$668.00	$314.00	$269.00	$897.00	$904.00	$912.00
Total O&M Costs ($K)				$20,298.00	$19,952.00	$16,717.00	$18,169.00	$17,416.00	$23,658.00
Variable O&M Cost ($/MWh)									
Forced & Planned Outages				2018	2019	2020	2021	2022	2023
Planned Outage Cost ($K)									
Forced Outage Costs ($K)									
Property Tax				2018	2019	2020	2021	2022	2023
Property Tax Payments ($K)				$4,393.00	$4,512.00	$4,205.00	$4,026.00	$4,252.00	$4,358.00
Property Tax Abatements ($K)									
5.10: Capital Expenditures				2018	2019	2020	2021	2022	2023
Annual CAPEX Actual and Budgeted (excluding LTSA) ($K)				$741,838.11	$629,604.94	$5,803,279.77	$4,045,250.00	$4,000,000.00	$4,000,000.00
LTSA CAPEX Actual and Budgeted ($K)									
5.15 Operating Data									
Unit 1		2016	2017	2018	2019	2020	2021	2022	2023
Unit Generation (Net MWh)				673990.0	881903.0	974555.0			
Commercial Operation Date	7/1/1999								
Annual Run Hours				3800.964	4973.052	5556.468			
Annual Operating Cycles									
Capacity Factor (%)				43.39%	56.77%	63.43%			
Availability Factor (%)				93.48%	85.01%	97.46%			
Average Heat Rate (MMBtu/MWh)				9500.0	9500.0	9500.0			
MISO Planning Year XEFORd (%)				1.23%	1.31%	0.90%			
Forced Outage Rate (%)							1.57%	1.57%	1.57%
Planned Maintenance Days							14.0	14.0	14.0

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

						Historic	Budgeted/Forecasted		
		2016	2017	2018	2019	2020	2021	2022	2023
Unit 2		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)				1,329,119	1,380,810	1,303,480			
Commercial Operation Date	7/1/2001								
Annual Run Hours				7313	7591	7231			
Annual Operating Cycles									
Capacity Factor (%)				83.48%	86.66%	82.55%			
Availability Factor (%)				91.58%	91.61%	89.41%			
Average Heat Rate (MMBtu/MWh)				7200	7200	7200			
MISO Planning Year XEFORd (%)				0.20%	0.24%	0.37%			
Forced Outage Rate (%)							0.93%	0.93%	0.93%
Planned Maintenance Days							14.0	14.0	14.0
Unit 3		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)				1,291,138	1,408,735	1,250,217			
Commercial Operation Date	7/1/2001								
Annual Run Hours				7280	7939	6898			
Annual Operating Cycles									
Capacity Factor (%)				83.11%	90.63%	78.74%			
Availability Factor (%)				91.51%	94.43%	86.22%			
Average Heat Rate (MMBtu/MWh)				7500	7500	7500			
MISO Planning Year XEFORd (%)				0.90%	1.01%	0.42%			
Forced Outage Rate (%)							0.76%	0.76%	0.76%
Planned Maintenance Days							14.0	14.0	14.0
Unit 4		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)				1,560,379	1,691,898	1,500,834			
Commercial Operation Date	7/1/2001								
Annual Run Hours				8751	8748	8746			
Annual Operating Cycles									
Capacity Factor (%)				99.90%	99.86%	99.84%			
Availability Factor (%)				99.9%	99.9%	99.8%			
Average Heat Rate (MMBtu/MWh)				14000	14000	14000			
MISO Planning Year XEFORd (%)				0.10%	0.14%	0.16%			
Forced Outage Rate (%)							0.44%	0.44%	0.44%
Planned Maintenance Days							14.0	14.0	14.0

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

	Input	Historic 2016	2017	2018	2019	2020	Budgeted/Forecasted 2021	2022	2023
Start Up									
Heat Rate during Startup (MMBtu/MWh)									
Time for Startup (Hours)									
Heat Input Required for Startup (MMBtu)									
Ramp Pre-Dispatch MWh									
Total Annual Hours Assumed in Startup Mode									
Average Run-Time per Start (Hours)									
Heat Rate during Shutdown (MMBtu/MWh)									
Time for Shutdown (Hours)									
Ramp Post-Dispatch MWh									
Total Annual Hours Assumed in Shutdown Mode									
Total Annual Hours Assumed at Full Load									
Total Annual Hours Excluding Startup & Shutdown at less than Full Load									
Estimated Heat Rate for the Above Condition (MMBtu/MWh)									
Maintenance History									
Unit 1									
Date of Last Inspection	2017								
Total Number of Equivalent Starts	2014								
Total Number of Equivalent Operating Hours	31372								
Total Number of Equivalent Starts Since Last Major Maintenance									
Total Number of Equivalent Operating Hours Since Last Major Maintenance									
Unit 2									
Date of Last Inspection	2015								
Total Number of Equivalent Starts	2634								
Total Number of Equivalent Operating Hours	87879								
Total Number of Equivalent Starts Since Last Major Maintenance									
Total Number of Equivalent Operating Hours Since Last Major Maintenance	38382								

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent: **CMS Enterprises**

Instructions
Respondents are to fill out the highlighted input cells in the form below.

						Historic	Budgeted/Forecasted		
		2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit 3									
Date of Last Inspection	2015								
Total Number of Equivalent Starts	2713								
Total Number of Equivalent Operating Hours	86883								
Total Number of Equivalent Starts Since Last Major Maintenance									
Total Number of Equivalent Operating Hours Since Last Major Maintenance	36745								
Unit 4									
Date of Last Inspection									
Total Number of Equivalent Starts									
Total Number of Equivalent Operating Hours									
Total Number of Equivalent Starts Since Last Major Maintenance									
Total Number of Equivalent Operating Hours Since Last Major Maintenance									
5.16: Acquisition Price									
Acquisition Price ($)	$473,000,000								

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

					Historic	Budgeted/Forecasted		
	2016	2017	2018	2019	2020	2021	2022	2023
5.4: Net Capability of Generating Facility								
Nameplate Capacity (MW)					75.0			
	Feb	Mar	Apr	May	Jun			
	75.0	75.0	70.0	70.0	70.0			
Net Monthly Capability (MW)	Aug	Sep	Oct	Nov	Dec			
	70.0	70.0	70.0	75.0	75.0			
5.6: Generation Technology								
5.7: MISO UCAP	2016	2017	2018	2019	2020	2021	2022	2023
UCAP (MW)	-	-	69.0	67.0	71.0	74.0	70.0	70.0
5.8: Heat Rates and Emission Rates								
	x	x^2	x^3	x^4	x^5			
Heat Rate Curve								
No Load Cost ($/hour)								
Avg Minimum Load Heat Rate (MMBtu/MWh)								
Incremental Heat Rates (MMBtu/MWh) at:								
50% of Full Load								
75% of Full Load								
Avg Full Load Heat Rate (MMBtu/MWh)								
Incremental Duct Firing Heat Rate (MMBtu/MWh)								
NOx (lb/MMBtu)								
SO_2 (lb/MMBtu)								
CO_2 (lb/MMBtu)								
VOC (lb/MMBtu)								
PM (lb/MMBtu)								
CO (lb/MMBtu)								

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Instructions
Respondents are to fill out the highlighted input cells in the form below.

Name of Respondent:
CMS Enterprises

	2016	2017	2018	2019	2020	2021	2022	2023
					Historic	**Budgeted/Forecasted**		
5.9: Operating Costs and Revenues			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Variable, non-fuel O&M Cost (excluding LTSA) ($K)								
Variable LTSA Related O&M Cost ($K)								
Delivered Fuel Costs ($K)			$648.00	$3,184.00	$4,701.00	$2,466.00	$2,500.00	$2,553.00
Fixed O&M Costs (excluding LTSA) ($K)			$1,390.00	$1,788.00	$1,734.00	$1,701.00	$1,743.00	$1,787.00
Fixed LTSA Related O&M Cost ($K)								
Total O&M Costs ($K)								
Variable O&M Cost ($/MWh)								
Forced & Planned Outages			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Planned Outage Cost ($K)								
Forced Outage Costs ($K)								
Property Tax			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Property Tax Payments ($K)			$147.00	$172.00	$171.00	$246.00	$252.00	$258.00
Property Tax Abatements ($K)								
5.10: Capital Expenditures			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Annual CAPEX Actual and Budgeted (excluding LTSA			$3,209,993.00	$7,103,815.38	$1,825,000.00	$1,825,000.00	$500,000.00	$500,000.00
LTSA CAPEX Actual and Budgeted ($K)								
5.15 Operating Data								
Unit 1	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Capacity Factor (%)			1.54%	9.23%	12.02%			
Availability Factor (%)			92.05%	86.48%	97.88%			
Average Heat Rate (MMBtu/MWh)			12500.0	12500.0	12500.0			
MISO Planning Year XEFORd (%)			1.31%	1.31%	1.46%			
Forced Outage Rate (%)						1.48%	1.48%	1.48%
Planned Maintenance Days						5.0	5.0	5.0

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

					Historic	Budgeted/Forecasted		
	2016	2017	2018	2019	2020	2021	2022	2023
Unit 2	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)								
Commercial Operation Date								
Annual Run Hours								
Annual Operating Cycles								
Capacity Factor (%)								
Availability Factor (%)								
Average Heat Rate (MMBtu/MWh)								
MISO Planning Year XEFORd (%)								
Forced Outage Rate (%)								
Planned Maintenance Days								
Unit 3	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)								
Commercial Operation Date								
Annual Run Hours								
Annual Operating Cycles								
Capacity Factor (%)								
Availability Factor (%)								
Average Heat Rate (MMBtu/MWh)								
MISO Planning Year XEFORd (%)								
Forced Outage Rate (%)								
Planned Maintenance Days								
Unit 4	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)								
Commercial Operation Date								
Annual Run Hours								
Annual Operating Cycles								
Capacity Factor (%)								
Availability Factor (%)								
Average Heat Rate (MMBtu/MWh)								
MISO Planning Year XEFORd (%)								
Forced Outage Rate (%)								
Planned Maintenance Days								

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

	2016	2017	2018	2019	2020	2021	2022	2023
					Historic	Budgeted/Forecasted		
Start Up								
Heat Rate during Startup (MMBtu/MWh)								
Time for Startup (Hours)								
Heat Input Required for Startup (MMBtu)								
Ramp Pre-Dispatch MWh								
Total Annual Hours Assumed in Startup Mode								
Average Run-Time per Start (Hours)								
Heat Rate during Shutdown (MMBtu/MWh)								
Time for Shutdown (Hours)								
Ramp Post-Dispatch MWh								
Total Annual Hours Assumed in Shutdown Mode								
Total Annual Hours Assumed at Full Load								
Total Annual Hours Excluding Startup &								
Estimated Heat Rate for the Above								
Maintenance History								
Unit 1								
Date of Last Inspection								
Total Number of Equivalent Starts								
Total Number of Equivalent Operating Hours								
Total Number of Equivalent Starts Since								
Total Number of Equivalent Operating Hours								
Unit 2								
Date of Last Inspection								
Total Number of Equivalent Starts								
Total Number of Equivalent Operating Hours								
Total Number of Equivalent Starts Since								
Total Number of Equivalent Operating Hours								

APPENDIX E - CEC 2021 RFP Request for Proposals Natural Gas Simple and Combined Cycle Generating Assets						**Name of Respondent:** **CMS Enterprises**		
Instructions Respondents are to fill out the highlighted input cells in the form below.								
					Historic	**Budgeted/Forecasted**		
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit 3								
Date of Last Inspection								
Total Number of Equivalent Starts								
Total Number of Equivalent Operating Hours								
Total Number of Equivalent Starts Since								
Total Number of Equivalent Operating Hours								
Unit 4								
Date of Last Inspection								
Total Number of Equivalent Starts								
Total Number of Equivalent Operating Hours								
Total Number of Equivalent Starts Since								
Total Number of Equivalent Operating Hours								
5.16: Acquisition Price								
Acquisition Price ($)								

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

	2016	2017	2018	2019	2020 (Historic)	2021 (Budgeted/Forecasted)	2022	2023
5.4: Net Capability of Generating Facility								
Nameplate Capacity (MW)					132.0			
	Feb	Mar	Apr	May	Jun			
	75.0	75.0	70.0	70.0	70.0			
Net Monthly Capability (MW)	Aug	Sep	Oct	Nov	Dec			
	70.0	70.0	70.0	75.0	75.0			
5.6: Generation Technology								
5.7: MISO UCAP	2016	2017	2018	2019	2020	2021	2022	2023
UCAP (MW)	-	-	125.0	126.0	127.0	120.0	114.0	114.0
5.8: Heat Rates and Emission Rates								
	x	x^2	x^3	x^4	x^5			
Heat Rate Curve								
No Load Cost ($/hour)								
Avg Minimum Load Heat Rate (MMBtu/MWh)								
Incremental Heat Rates (MMBtu/MWh) at:								
50% of Full Load								
75% of Full Load								
Avg Full Load Heat Rate (MMBtu/MWh)								
Incremental Duct Firing Heat Rate (MMBtu/MWh)								
NOx (lb/MMBtu)								
SO_2 (lb/MMBtu)								
CO_2 (lb/MMBtu)								
VOC (lb/MMBtu)								
PM (lb/MMBtu)								
CO (lb/MMBtu)								

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

	2016	2017	2018	2019	2020	2021	2022	2023
					Historic	Budgeted/Forecasted		
5.9: Operating Costs and Revenues			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Variable, non-fuel O&M Cost (excluding LTSA) ($K)								
Variable LTSA Related O&M Cost ($K)								
Delivered Fuel Costs ($K)			$557.00	$934.00	$479.00	$267.00	$272.00	$279.00
Fixed O&M Costs (excluding LTSA) ($K)			$1,128.00	$1,901.00	$1,090.00	$1,197.00	$1,228.00	$1,259.00
Fixed LTSA Related O&M Cost ($K)								
Total O&M Costs ($K)								
Variable O&M Cost ($/MWh)								
Forced & Planned Outages			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Planned Outage Cost ($K)								
Forced Outage Costs ($K)								
Property Tax			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Property Tax Payments ($K)			$162.00	$163.00	$161.00	$160.00	$164.00	$168.00
Property Tax Abatements ($K)								
5.10: Capital Expenditures			**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Annual CAPEX Actual and Budgeted (excluding LTSA			$0.00	$0.00	$1,458,288.91	$1,090,000.00	$500,000.00	$500,000.00
LTSA CAPEX Actual and Budgeted ($K)								
5.15 Operating Data								
Unit 1	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Capacity Factor (%)			0.36%	0.66%	0.26%			
Availability Factor (%)			98.36%	96.44%	94.00%			
Average Heat Rate (MMBtu/MWh)			16000.0	16000.0	16000.0			
MISO Planning Year XEFORd (%)			1.84%	4.55%	3.17%			
Forced Outage Rate (%)						11.87%	8.00%	5.00%
Planned Maintenance Days						5.0	5.0	5.0

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

					Historic	Budgeted/Forecasted		
	2016	2017	2018	2019	2020	2021	2022	2023
Unit 2	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)			1,244	197	1,322			
Commercial Operation Date								
Annual Run Hours			39	6	41			
Annual Operating Cycles								
Capacity Factor (%)			0.44%	0.07%	0.47%			
Availability Factor (%)			100.00%	95.07%	88.26%			
Average Heat Rate (MMBtu/MWh)			16000.0	16000.0	16000.0			
MISO Planning Year XEFORd (%)			8.56%	4.55%	3.17%			
Forced Outage Rate (%)						6.94%	5.00%	5.00%
Planned Maintenance Days						5.0	5.0	5.0
Unit 3	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)			1,066	10,212	1,727			
Commercial Operation Date								
Annual Run Hours			33	319	53			
Annual Operating Cycles								
Capacity Factor (%)			0.38%	3.64%	0.61%			
Availability Factor (%)			100.00%	96.44%	100.00%			
Average Heat Rate (MMBtu/MWh)			16000.0	16000.0	16000.0			
MISO Planning Year XEFORd (%)			1.84%	4.55%	3.56%			
Forced Outage Rate (%)						9.01%	7.00%	5.00%
Planned Maintenance Days						5.0	5.0	5.0
Unit 4	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit Generation (Net MWh)			1,168	353	98			
Commercial Operation Date								
Annual Run Hours			37	11	3			
Annual Operating Cycles								
Capacity Factor (%)			0.42%	0.13%	0.03%			
Availability Factor (%)			91.5%	56.4%	37.2%			
Average Heat Rate (MMBtu/MWh)			16000.0	16000.0	16000.0			
MISO Planning Year XEFORd (%)			1.84%	4.55%	1.74%			
Forced Outage Rate (%)						3.10%	3.00%	3.00%
Planned Maintenance Days						5.0	5.0	5.0

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

					Historic	**Budgeted/Forecasted**		
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Start Up								
Heat Rate during Startup (MMBtu/MWh)								
Time for Startup (Hours)								
Heat Input Required for Startup (MMBtu)								
Ramp Pre-Dispatch MWh								
Total Annual Hours Assumed in Startup Mode								
Average Run-Time per Start (Hours)								
Heat Rate during Shutdown (MMBtu/MWh)								
Time for Shutdown (Hours)								
Ramp Post-Dispatch MWh								
Total Annual Hours Assumed in Shutdown Mode								
Total Annual Hours Assumed at Full Load								
Total Annual Hours Excluding Startup &								
Estimated Heat Rate for the Above								
Maintenance History								
Unit 1								
Date of Last Inspection								
Total Number of Equivalent Starts								
Total Number of Equivalent Operating Hours								
Total Number of Equivalent Starts Since								
Total Number of Equivalent Operating Hours								
Unit 2								
Date of Last Inspection								
Total Number of Equivalent Starts								
Total Number of Equivalent Operating Hours								
Total Number of Equivalent Starts Since								
Total Number of Equivalent Operating Hours								

APPENDIX E - CEC 2021 RFP
Request for Proposals
Natural Gas Simple and Combined Cycle Generating Assets

Name of Respondent:
CMS Enterprises

Instructions
Respondents are to fill out the highlighted input cells in the form below.

					Historic	Budgeted/Forecasted		
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Unit 3								
Date of Last Inspection								
Total Number of Equivalent Starts								
Total Number of Equivalent Operating Hours								
Total Number of Equivalent Starts Since								
Total Number of Equivalent Operating Hours								
Unit 4								
Date of Last Inspection								
Total Number of Equivalent Starts								
Total Number of Equivalent Operating Hours								
Total Number of Equivalent Starts Since								
Total Number of Equivalent Operating Hours								
5.16: Acquisition Price								
Acquisition Price ($)								

Question:

24. Refer to your response to MEC-CE-28.
a. Further refer to your response to MEC-CE-28(b)(ii). Please confirm that the Company does not intend to update or supplement the community transition plan
for Karn 1 and 2.
i. If not confirmed, please describe any plans to update/supplement the plan, including the timeline for such supplementation.
ii. Will the Company submit an updated community transition plan with its June 2021 IRP filing?
b. Refer to your response to MEC-CE-28(d) which discusses the development of an alternatives analysis.
i. Please identify the person(s) or entity(ies) that will be performing this analysis.
ii. When will this analysis will be completed?
iii. Will the results of this analysis be presented in the Company's IRP filing?
If not, please describe any plans to share the results of this analysis publicly.
c. Refer to your response to MEC-CE-28(e). Please describe the composition of the workforce planning team. Will this team be led by the Company, or an outside contractor?
d. Refer to your response MEC-CE-28(f)
i. Please share any written materials that the Company presented at the meetings with the Hampton Township Supervisor and Bay Future.
ii. Does the Company plan to take any follow-up actions as a result of these meetings?
iii. Who will be invited to the virtual quarterly update meetings? Are those meetings open to the interested public?
iv. Please state whether the first quarterly update has been scheduled, and if so, when such meeting has or will be held.
e. Refer to your response to MEC-CE-28(h). When is the contractor scheduled to provide a draft of the future use study?

Response:

a. **Objection of Counsel: Consumers Energy Company objects to this discovery request because it is irrelevant and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:**
   i. The plan presented in the 2018 IRP is the current plan.
   ii. See subpart (i).
b. **Objection of Counsel: Consumers Energy Company objects to this discovery request because it is unclear, irrelevant, overly broad, and not proportional to the needs of this case.**
c. **Objection of Counsel: Consumers Energy Company objects to this discovery request because it is unclear, irrelevant, overly broad, and not proportional to the needs of this case.**

d. **Objection of Counsel:** **Consumers Energy Company objects to this discovery request because it is unclear, irrelevant, overly broad, and not proportional to the needs of this case.**

e. **Objection of Counsel:** **Consumers Energy Company objects to this discovery request because it is unclear, irrelevant, overly broad, and not proportional to the needs of this case.**

Scott A. Hugo
May 14, 2021

Director – Generation Asset Strategy

<u>Question:</u>

22. Refer to your response to MEC-CE-53:

a. Does Consumers intend to update its community transition plan? If so, please identify the associated timeline for an updated transition plan.

b. Please provide a copy of the grant application and/or project scope associated with the Hampton Township EDA grant for which the Company is on the steering committee.

c. Does Consumers intend to develop a formal future use study for the Karn site? If so, what is the current anticipated timeline for such study?

d. What opportunities would be available to Karn employees at a potential solar site constructed on the Karn site?

<u>Response:</u>

a. Yes. Consumers Energy does intend to update its community transition plan in the second half of 2020. The Company plans to further develop and update the plan with drafts expected 3rd to 4th quarter of 2020.

b. See Attachment U20697-MEC-CE-549_ATT_1 for a copy of the Hampton Township EDA grant application and Attachment U20697-MEC-CE-549_ATT_2 for a copy of the confirmation of grant submittal.

c. Consumers Energy is currently planning to solicit proposals and complete a future use study between the 3rd quarter of 2020 and 2nd quarter of 2021.

d. A draft strategy will continue to be developed throughout 2020-2021 which quantifies renewable generation resource opportunities and training requirements within our workforce action planning efforts.

Scott A. Hugo
May 1, 2020

Director – Generation Asset Strategy

Question:

22. Refer to your response to MEC-CE-549.
a. Is the Company consulting with community groups and/or community leaders in updating the Karn community transition plan? If so, please name which community groups/leaders it is consulting with.
b. Does the Company plan to conduct a public forum to receive input on an updated community transition plan?
c. Further refer to your response to MEC-CE-549(c). Please identify who the Company is soliciting proposals from (or plans to solicit proposals from) for the future use study.
d. Further refer to your response to MEC-CE-549(d). Will renewable generation resource opportunities be available to current Karn employees who cannot continue their employment with the Company following the retirement of Karn 1&2?

Response:

a. No. The Company is not consulting with community groups or community leaders in updating the plan.

b. No. The Company does not plan to conduct a public forum to receive input on an updated community transition plan. The Community transition plan is a business confidential document for Company use only.

c. No determination regarding plans for the solicitation of proposals for a future use study has been made.

d. No determination regarding the availability of renewable generation resource availabilities for current Karn employees who cannot continue their employment with the Company following the retirement of Karn 1&2 has been made. However, this opportunity will be taken into consideration as our coal plant retirement strategy moves forward in the years to come.

Scott A. Hugo
May 29, 2020

Director – Generation Asset Strategy

Question:

21. Refer to pages 49-57 of the Direct Testimony of Norman J. Kapala in Case No. U-20165, and to discovery response U20697-MEC-CE-53 from Case No. U-20697.

   a. Please produce in discovery in this case (or, alternatively, indicate permission to use in this case) the Karn community transition plan, which was provided in Case U-20796 as confidential discovery attachment "U20697-MEC-CE-053- Hugo_CONF_ATT_1."

   b. Further refer to U20697-MEC-CE-053(a)(i), which notes that the Karn community transition plan has not "been updates since [it was] provided in Case No. U-20165."

      At present – i.e., as of April 5, 2021 – has the community transition plan been updated since Case No. U-20165?

      i. If so, please provide a copy of the current version of the community transition plan.

      ii. If not, please explain why not.

   c. Please identify actual or projected expenditures for each of the years 2020-2024 associated with implementing (i) the community transition plan, and (ii) the future use study.

   d. Please describe in detail any plans by the Company to assist in the economic redevelopment of areas that will likely be affected by the retirement of Karn 1 and 2.

   e. Please describe any workforce retraining opportunities Consumers has made or is planning to make available for Karn employees.

   f. Please identify and describe any attempt Consumers has made since April 2020 to get community input or engage in public participation planning related to the Karn retirements. (Such attempts include, but are not limited to, holding formal or informal public meetings, meeting with local officials, and meeting with community stakeholders.)

   g. Has Consumers entered into any community benefit agreement related to the planned retirement of Karn 1 and 2? If so, please identify and provide a copy of such agreement.

   h. Further refer to discovery response U20697-MEC-CE-059(c) from Case No. U-20697, which notes the Company's intention to complete a future use study for the Karn site "between the 3rd quarter of 2020 and 2nd quarter of 2021." Please provide an update on the status of these efforts, and produce the current version of any future use study related to Karn.

Response:

> **Objection of Counsel:** **Consumers Energy Company objects to this discovery request to the extent that it is irrelevant and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:**

a. The Company grants the permission for use in this case the Karn community transition plan which was provided as confidential discovery attachment U20697-MEC-CE-053-Hugo_CONF_ATT_1.

b. No changes have been made to this document since it was provided in U-20165.
   i. Not applicable.
   ii. The community transition plan is based on the planned retirement of Karn Units 1 and 2. In Case No. U-20165, the parties to the approved IRP Settlement Agreement agreed that Karn Units 1 and 2 will retire in 2023. There have been no changes to the agreed upon retirement date of Karn Units 1 and 2.

c. Please see attachment U20963-MEC-CE_028_ATT_1 for a preliminary estimate of costs for 2020-2024. The Company is currently in the process of developing an updated IRP to be filed in June 2021, which may influence any updates/revisions to the document. Additional questions regarding this document would be more appropriate for that proceeding.

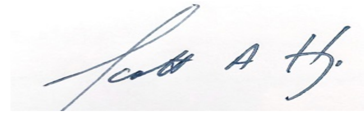
d. An alternatives analysis will be completed during the upcoming Karn Unit 1 and 2 retirement process identifying which redevelopment scenarios may best fit the relevant available properties. This will occur during the course of 2021.

e. The Company is currently assembling a workforce planning team to identify, review and implement actionable retraining opportunities. However, the Company is not yet at a point of detail where individual areas of identification have occurred. This is expected to be accomplished in a late 2021-2022 timeframe.

f. Due to COVID19 restrictions, update and alignment opportunities with local Stakeholders have been restrained. The Company plans to begin virtual quarterly updates again in 2021 starting 1st to 2nd quarter. An organic meeting with Hampton Township Supervisor was held on Monday, April 5th 2021 to provide an opportunity for any questions or relevant updates in Karn Site activity related to ongoing decommissioning efforts. Similarly, a meeting with Bay Future is taking place on April 7th 2021.

g. No. Consumers Energy has not entered into any such agreement.

h. The future use/alternatives analysis study process is in progress and as mentioned in the referenced statement, "between the 3rd quarter of 2020 and 2nd quarter of 2021". Solicitation and award has been completed and the awarded Contractor will provide a draft according to the communicated schedule.



Scott A. Hugo
April 13, 2021

Director – Generation Asset Strategy

Question:

55. Refer to page 62, lines 19-21 of the Kapala Direct Testimony.
a. Please provide a copy of the most up-to-date community transition plans for each of the Classic 7.
b. Please provide a copy of the most up-to-date community transition plan for Karn 1&2. If the Company claims that any portion of this plan is confidential, please provide (i) an unredacted confidential copy (subject to the protective order in this case, and (ii) a public copy (with redactions of any material claimed to be confidential).
i. If not already specified in the document itself, please identify the date when the Karn 1&2 transition plan was last updated.
c. Does the Company intend to update the Karn 1&2 transition plan in light of the proposed retirement of Karn 3&4? If so, please describe the timeline for updating the Karn 1&2 plan.
d. Further refer to Kapala Direct, page 62, line 18 through page 63, line 2, and page 64, lines 9-18. Please describe the timeline for completing a future-use study for the entire Karn-Weadock complex (or for Karn 3&4, if those units' future use will be evaluated separately).
e. Further to page 65, line 20 through page 67, line 8, which discusses transition issues related to Campbell.
i. Please describe the timeline for developing a community transition plan for the Campbell plant.
ii. Please describe the timeline for completing a future-use study for the Campbell site.

Response:

a. Please see Attachment U21090_MEC-CE-089_ATT_1 Confidential for the most up-to-date community transition plan for each of the Classic 7.

b. Please see Attachment U21090_MEC-CE-089_ATT_2 Confidential for the most up-to-date community transition plan for Karn 1 and 2.

c. A community transition plan would be developed encompassing Karn units 1-4 should the Company's PCA be approved. A timeline has yet to be determined.

d. A timeline to complete the future use study on a sitewide perspective has yet to be determined.

e. i. A timeline has yet to be determined.

ii. A timeline has yet to be determined.

Norman J. Kapala
August 20, 2021

Executive Director – Fossil and Renewable Generation

Question:

56. Refer to discovery response U20963-MEC-CE-028 from Case No. U-20963.
a. Further refer to U20963-MEC-CE-028(h), which indicates that the contractor would provide a draft of the Karn 1&2 future-use study between "between the 3rd quarter of 2020 and 2nd quarter of 2021." Please provide a copy of the draft future-use study for the Karn site.
b. Further refer to U20963-MEC-CE-028(e), which states: "The Company is currently assembling a workforce planning team to identify, review and implement actionable retraining opportunities." Please describe the composition of the workforce planning team. Will this team be led by the Company, or an outside contractor?
c. Further refer to U20963-MEC-CE-028(f), which states "[t]he Company plans to begin virtual quarterly updates again in 2021 starting 1st to 2nd quarter."
i. Please state whether the first quarterly update has been scheduled, and if so, when such meeting has or will be held.
ii. Who will be invited to the virtual quarterly update meetings? Are those meetings open to the interested public?

Response:

a. An alternatives analysis for the retirement of Karn units 1&2 has been completed and is attached as U21090-MEC-CE-090_ATT_1. A future use study focused on the Karn Site has not been scheduled to-date.

b. The team is currently comprised of only internal Consumers Energy resources; organizational Human Resources representatives, Plant and Site Management representatives, Stakeholder Engagement representatives, Enterprise Resource Planning representatives, Facilities Planning representatives, Labor Relations representatives, People and Culture representatives and Learning and Development representatives. This team will be led by the Company.

c.

i. The referenced meeting was held on 04/23/2021.

ii. Attendees invited are Consumers Energy representatives and local area governing stakeholders such as: Hampton Township Supervisor, Bay County Executive, Bangor Township Supervisor, City of Essexville Mayor, and President & CEO Bay Future. The meetings are not open to the public.

Norman J. Kapala
August 20, 2021

Executive Director – Fossil and Renewable Generation

MEC-39C

CONFIDENTIAL EXHIBIT

<u>Question:</u>

9. For each site, Karn/Weadock and Campbell:
a. Please discuss what the community and/or municipality impacts will be assuming a retirement date as proposed in this current IRP case, if known.
b. How has the Company prepared the community for this retirement?
c. When did conversations start about the retirements in 2023 and 2025?
d. Since the Company is proposing to collect the remaining net book value of these plants until the end of their design life, will the Company also be paying taxes as if the facilities are operating?

<u>Response:</u>

a. Pages 61 and Page 65 of my testimony address the community property tax impacts related to Karn Units 3&4 and Campbell Units 1-3. Over the last 5 years, the Company's tax team and each community's tax assessor have discussed the declining value of fossil-fuel generation for property tax purposes. The local assessors have reduced and continue to reduce each unit's annual tax assessment to reflect this decline in value.

   With respect to employees, approximately 300 people support day-to-day facility operations at the Campbell complex and about approximately 80 people support day-to-day operations at Karn 3&4. The Company is committed to working with all impacted employees to retain them within the Company and also allow them to stay as close to home as possible, but there is a chance some may need to leave their community to work elsewhere within the Company. There is also potential impact to local contractors, businesses, and services. While the Company commissioned a detailed future use study for the Karn site, the Company plans to commission a study for the Campbell site before the second quarter of 2022. Our strong relationships with local economic development organizations and chambers serve the Company well as we work together to discuss potential site opportunities and redevelopment. Tax revenue will be impacted, and open and honest discussions with local townships will occur to help them plan for their future. It should be noted that an early closure of Karn Units 3&4 would accelerate the redevelopment process, providing an opportunity for generating a future tax base sooner in comparison to a closure in 2031.

b. Just as we did with the closing of our Classic 7, we embrace the Just Transition framework by gathering information and intelligence, engaging the community, visualizing scenarios and helping to build solutions The Company continues to be fully committed to community stakeholder collaboration and an ordered transition process at each of our remaining sites.

   Our goal is to smoothly transition through open communication and regional sustainable vision alignment. Future use studies and collaboration with community stakeholders have been key with our Classic 7 decommissioning process. Our partners include the community residents, government officials, state elected officials, economic development organizations, vendors, state agencies and employees affected by the closure.

Moving forward, our Company maintains strong, trusted relationships in support of Hampton Township and the Bay region as we continue to decommission our D.E Karn Generating Complex. That same care and commitment will be shown to Ottawa County and the Campbell Generating Complex community. We maintain quarterly meetings with key community stakeholders as they re-imagine the local economic landscape before, during and after decommissioning. We utilize Karn's future use study to help visualize the possibilities for the site and will do the same when we commission a future use study for Campbell. To date, the demolition of Weadock is complete, and part of the site is blooming as a new habitat for butterflies, bees, and other pollinators.

See also the response to subpart (a) regarding annual discussions with respect to property tax assessments.

c. Our Community Affairs team, who have established relationships with the Karn and Campbell community leaders, set up appointments to share the 2021 Clean Energy Plan immediately following the June 23rd announcement to our Karn and Campbell employees. In the D.E. Karn community, the Community Affairs team met with the Hampton Township supervisor, President of Bay Future, Bay County Chamber President and Bay County Executive. In the Campbell community, the Community Affairs team met with the County Administrator, Port Sheldon Supervisor, Grand Haven Area Public Schools Superintendent, and President of Lakeshore Advantage. From that day forward, quarterly meetings with stakeholders were scheduled, including a discussion about how the acceleration of the closures will impact taxes within the regions.

d. Michigan's General Property Tax Act requires annual property taxes to be based on the true cash value of the assets as of each December 31st. Upon closure of the sites, we expect the tax assessments to reflect the residual value of the land and buildings. Therefore, we do not expect to pay property taxes as if the facilities are operating coal-fired generating plants.

Norman J. Kapala
August 31, 2021

Executive Director – Fossil and Renewable Generation

Question:

1. When did the Company first reach out to the communities that receive tax dollars from Campbell and Karn units about significant acceleration of the coal and gas/oil retirement? Please provide dates and communities that communication was had.

Response:

On June 23rd we shared the IRP announcement with Bay and Ottawa county stakeholders who would be financially impacted by the retirements. On July 13th our Director of Corporate Tax and Manager of Stakeholder Relations met with Hampton Township officials to share the projected decrease in tax revenue, and a meeting of the same nature is scheduled with Port Sheldon Township officials for September 29th.

Norman J. Kapala
October 4, 2021

Executive Director – Fossil and Renewable Generation

Question:

2. Has the Company received information or feedback that those communities support the retirement of the coal and gas/oil units? If so, please provide comments.

Response:

Since the announcement of the IRP, the Company has met with stakeholders in Bay and Ottawa counties, and both communities stated that they understand the environmental concerns associated with coal and oil to generate electricity and support our plan to ensure reliability with renewable energy.

In addition to the feedback from those communicates that are directly impacted by the announcement, Appendix 02 (Stakeholder Engagement Report) of the Company's 2021 Clean Energy Plan (Exhibit No.: A-2(RTB-2), contains multiple comments and Company responses to the Company's public outreaches and technical workshops.

Please also refer to the Company's response to discovery question U21090-ST-CE-271.

Norman J. Kapala
October 4, 2021

Executive Director – Fossil and Renewable Generation

Question:

3. Has the Company received information or feedback about concerns that those communities have? If so, please provide the concerns.

Response:

The Company's reputation for successfully guiding former coal plant communities through the decommissioning process is duly noted by the communities, and discussions about economic development and transformation opportunities have been positive. While both communities are concerned about the potential decrease in tax revenue, discussions about a pragmatic approach have occurred and stakeholders are engaged.

In addition to the feedback and concerns from those communities that are directly impacted by the announcement, Appendix 02 (Stakeholder Engagement Report) of the Company's 2021 Clean Energy Plan (Exhibit No.: A-2(RTB-2), contains multiple comments and Company responses to the Company's public outreaches and technical workshops.

Please also refer to the Company's response to discovery questions U21090-ST-CE-271 and U21090-ST-CE-272.

Norman J. Kapala
October 4, 2021

Executive Director – Fossil and Renewable Generation

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	U-21090 ALJ Sally Wallace

---

PROOF OF SERVICE

On the date below, an electronic copy of **PUBLIC Direct Testimony of Tyler Comings on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club; and PUBLIC Exhibits MEC-15 through MEC-18, MEC-24 through MEC-27, MEC-29, MEC-33, MEC-36 through MEC-38 and MEC-40** was served on the following:

Name/Party	E-mail Address
Administrative Law Judge Sally L. Wallace	wallaces2@michigan.gov
Counsel for Consumers Energy Co. Robert W. Beach Michael C. Rampe Gary A. Gensch, Jr. Ian F. Burgess Bret A. Totoraitis Anne M. Uitvlugt Theresa A. G. Staley	mpscfilings@cmsenergy.com Robert.beach@cmsenergy.com michael.rampe@cmsenergy.com gary.genschjr@cmsenergy.com ian.burgess@cmsenergy.com bret.totoraitis@cmsenergy.com anne.uitvlugt@cmsenergy.com theresa.staley@cmsenergy.com
Counsel for Michigan Public Service Commission Staff Spencer Sattler Amit Singh Benjamin Holwerda Nicholas Taylor Daniel Sonneveldt Lori Mayabb	sattlers@michigan.gov singha9@michigan.gov holwerdab@michigan.gov taylorn10@michigan.gov sonneveldtd@michigan.gov mayabbl@michigan.gov
Counsel for Attorney General Celeste Gill	AG-ENRA-Spec-Lit@michigan.gov Gillc1@michigan.gov
Counsel for ABATE Michael J. Patwell Stephen A. Campbell James Fleming	mpattwell@clarkhill.com scampbell@clarkhill.com jfleming@ClarkHill.com

Counsel for Cadillac Renewable Energy LLC, Genesee Power Partners Limited Partnership, Decker Energy- Grayling, LLC, Hillman Power Company, LLC Tondu Corporation, Viking Energy of Lincoln, LLC, Viking Power of McBain, LLC Thomas J. Waters	twaters@fraserlawfirm.com
Counsel for Midland Cogeneration Venture LP John A. Janiszewski	jjaniszewski@dykema.com
Counsel for Energy Michigan Inc., Michigan Energy Innovation Business Council, Institute for Energy Innovation and Clean Grid Alliance Laura Chappelle Timothy J. Lundgren	lchappelle@potomaclaw.com tlundgren@potomaclaw.com
Counsel for Hemlock Semiconductor Corp. Jennifer Utter Heston	jheston@fraserlawfirm.com
Counsel for GLREA Don L. Keskey Brian W. Coyer	donkeskey@publiclawresourcecenter.com bwcoyer@publiclawresourcecenter.com
Environmental Law & Policy Center, Ecology Center, Union of Concerned Scientists, and Vote Solar Margrethe M. Kearney Heather Vogel	mpscdockets@elpc.org mkearney@elpc.org hvogel@elpc.org
Counsel for Wolverine Power Supply Cooperative, Inc. Jason T. Hanselman Lauren E. Fitzsimons	jhanselman@dykema.com LFitzsimons@dykema.com
Counsel for Michigan Electric Transmission Company Richard Aaron	RAaron@dykema.com

Mackinac Center for Public Policy Jason Hayes Derk Wilcox	hayes@mackinac.org wilcox@mackinac.org
Urban Core Collective Nicholas Leonard Andrew Bashi Mark Templeton Robert Weinstock	nicholas.leonard@glelc.org andrew.bashi@glelc.org templeton@uchicago.edu rweinstock@uchicago.edu sgewirth@uchicago.edu aelc_mpsc@lawclinic.uchicago.edu
Michigan Public Power Agency Peter H. Ellsworth Nolan J. Moody	pellsworth@dickinsonwright.com nmoody@dickinsonwright.com
Citizens Utility Board Abigail Hawley	abbie@envlaw.com
Other Robert O'Meara	romeara@itctransco.com

The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC, NRDC, SC, CUB

Date: October 28, 2021

By: Karla L Gerds
Digitally signed by Karla Gerds
Date: 2021.10.28 11:35:30 -04'00'

Kimberly Flynn, Legal Assistant
Karla Gerds, Legal Assistant
Breanna Thomas, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231/946-0044
Email: kimberly@envlaw.com
karla@envlaw.com
breanna@envlaw.com

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	U-21090 ALJ Sally Wallace

---

CONFIDENTIAL PROOF OF SERVICE

On the date below, an electronic copy of **CONDENTIAL Direct Testimony of Tyler Comings on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club; and CONFIDENTIAL Exhibits MEC-19C, MEC-20C, MEC-21C, MEC-22C, MEC-23C, MEC-28C, MEC-30C, MEC-31C, MEC-32C, MEC-34C, MEC-35C and MEC-39C** was served on the following:

Name/Party	E-mail Address
Administrative Law Judge Sally Wallace	 Wallaces2@michigan.gov
Counsel for Consumers Energy Co. Robert W. Beach Michael C. Rampe Gary A. Gensch, Jr. Ian F. Burgess Bret A. Totoraitis Anne M. Uitvlugt Theresa A. G. Staley	mpscfilings@cmsenergy.com Robert.beach@cmsenergy.com michael.rampe@cmsenergy.com gary.genschjr@cmsenergy.com ian.burgess@cmsenergy.com bret.totoraitis@cmsenergy.com anne.uitvlugt@cmsenergy.com theresa.staley@cmsenergy.com
Counsel for Michigan Public Service Commission Staff Spencer Sattler Amit Singh Nicholas Taylor Bob Nichols	 sattlers@michigan.gov singha9@michigan.gov taylorn10@michigan.gov nicholsb1@michigan.gov
Counsel for Attorney General Celeste Gill Amanda Churchill	 Gillc1@michigan.gov churchilla1@michigan.gov

Counsel for Cadillac Renewable Energy LLC, Genesee Power Partners Limited Partnership, Decker Energy- Grayling, LLC, Hillman Power Company, LLC Tondu Corporation, Viking Energy of Lincoln, LLC, Viking Power of McBain, LLC Thomas J. Waters	twaters@fraserlawfirm.com
Counsel for Midland Cogeneration Venture LP John A. Janiszewski	jjaniszewski@dykema.com
Counsel for Energy Michigan Inc., Michigan Energy Innovation Business Council, Institute for Energy Innovation and Clean Grid Alliance Laura Chappelle Timothy J. Lundgren	lchappelle@potomaclaw.com tlundgren@potomaclaw.com
Counsel for Hemlock Semiconductor Corp. Jennifer Utter Heston	jheston@fraserlawfirm.com
Counsel for Wolverine Power Supply Cooperative, Inc. Jason T. Hanselman Lauren E. Fitzsimons Joseph Baumann	jhanselman@dykema.com LFitzsimons@dykema.com jbaumann@wpsci.com
Counsel for Michigan Electric Transmission Company Richard Aaron Olivia R.C.A Flower	RAaron@dykema.com oflower@dykema.com
Counsel for Mackinac Center for Public Policy Derk Wilcox	wilcox@mackinac.org
Counsel for Michigan Public Power Agency Peter H. Ellsworth Nolan J. Moody	pellsworth@dickinsonwright.com nmoody@dickinsonwright.com
Counsel for Urban Core Collective Mark Templeton Robert Weinstock Simone Gewirth	templeton@uchicago.edu rweinstock@uchicago.edu sgewirth@uchicago.edu

Counsel for Environmental Law & Policy Center, Ecology Center, Union of Concerned Scientists, and Vote Solar Margrethe M. Kearney Heather Vogel	mpscdockets@elpc.org mkearney@elpc.org hvogel@elpc.org
Counsel for GLREA and RCG Don Keskey	donkeskey@publiclawresourcecenter.com

The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC, NRDC, and SC

Date: October 28, 2021

Digitally signed by Karla Gerds
Date: 2021.10.28 11:35:09 -04'00'

By: ______________________________

Kimberly Flynn, Legal Assistant
Karla Gerds, Legal Assistant
Breanna Thomas, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231/946-0044
Email: kimberly@envlaw.com
karla@envlaw.com
breanna@envlaw.com