ENVIRONMENTAL LAW & POLICY CENTER

March 9, 2023

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

RE: MPSC Case No. U-21193

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Testimony on Behalf of Environmental Law & Policy Center, The Ecology Center, Union of Concerned Scientists and Vote Solar:

Kelsey Bilsback
Boratha Tan
Kevin Lucas

Proof of Service

Sincerely,

Daniel Abrams
Environmental Law & Policy Center
dabrams@elpc.org

cc: Service List, Case No. U-21193

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.	)))))	Docket No. U-21193 Administrative Law Judge Sharon Feldman

EXHIBIT LIST

ON BEHALF OF

THE ECOLOGY CENTER,
THE ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS,
AND VOTE SOLAR

March 9, 2023

MPSC Witness	Ex. #	Exhibit Description
William D. Kenworthy	CEO-1	Resume of William D. Kenworthy
	CEO-2	Testimony and Comments of William D. Kenworthy
	CEO-3	Comments of Vote Solar on the Draft MI Healthy Climate Plan: Modeling the Benefits of Electrification and Decarbonization in the Power Sector in Michigan, February 23, 2022
	CEO-4	MIACDE-4.1a
	CEO-5	U-21193 MNSCDE-2.11d 2017-2021 Capacity Factor
Chelsea Hotaling	CEO-6	Resume of Chelsea Hotaling
	CEO-7	DTE Supplemental response to CEODE 2.33a
James Gignac	CEO-8	Resume of James Gignac
	CEO-9	*Let Communities Choose: Clean Energy Sovereignty in Highland Park, Michigan*
	CEO-10	*Designing a Neighborhood Microgrid: Envisioning a Microgrid for the Parker Village Neighborhood in Highland Park, Michigan*
	CEO-11	*On the Road to 100 Percent Renewables: States Can Lead an Equitable Energy Transition*
	CEO-12	*On the Road to 100 Percent Renewables for Michigan: Strengthening the State's Energy Transition*
Boris Lukanov	CEO-13	Resume of Boris Lukanov
Kelsey Bilsback	CEO-14	Curriculum Vitae of Kelsey Bilsback
	CEO-15	CEO Emissions Analysis
	CEO-16	CEO Health Analysis
	CEO-17	CEO Equity Analysis

Boratha Tan	CEO-18	Resume of Boratha Tan
	CEO-19	dGen Step-by-Step Process
	CEO-20	dGen Results
	CEO-21	Community Solar and Storage Resilience
Kevin Lucas	CEO-22	Kevin M. Lucas CV
	CEO-23	*Carbon Capture and Sequestration (CCS) in the United States*, Congressional Research Service, October 2022
	CEO-24	MNSCDE-1
	CEO-25	*NETL's Updated Performance and Cost Estimates for Power Generation Facilities Equipped with Carbon Capture*, National Energy Technology Laboratory, U.S. Department of Energy, October 2022
	CEO-26	*Winter Storm Elliott Overview*, PJM, January 2023
	CEO-27	*Michigan Hosting Capacity Study*, ITC Michigan, 2021
	CEO-28	*Beyond Wires: Using Advanced Transmission Technologies to Accelerate the Transition to Clean Energy*, Environmental Law & Policy Center, May 2021
	CEO-29	*Interconnection Cost Analysis in the Midcontinent Independent System Operator (MISO) Territory*, Lawrence Berkeley National Laboratory, October 2022
	CEO-30	*Lessons from the Front Line: Principles and Recommendations for Large-scale and Distributed Energy Interconnection Reform*, SEIA, June 14, 2022
	CEO-31	*Comments of the Solar Energy Industries Association*, Docket No. RM22-14-000, October 13, 2022

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.	)))))	Docket No. U-21193 Administrative Law Judge Sharon Feldman

DIRECT TESTIMONY OF
DR. KELSEY BILSBACK

March 9, 2023

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I. <u>Name and Qualifications</u>

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

A: My name is Dr. Kelsey Bilsback (she/her). I am an employee of PSE Healthy Energy. My business address is 1440 Broadway, Suite 750, Oakland, California, 94612.

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

A: I appear here in my capacity as an expert witness on behalf of the Environmental Law & Policy Center, the Ecology Center, the Union of Concerned Scientists, and Vote Solar. Collectively, these parties are referred to as the Clean Energy Organizations or "CEO."

Q: Can you please summarize your educational background?

A: I have a PhD in Mechanical Engineering from Colorado State University and a BA in Physics from Boston University.

Q. Can you please summarize your work experience?

A: My work experience is outlined in detail in my resume, Exhibit CEO-14. Briefly, I am a senior scientist at PSE Healthy Energy with a background in mechanical engineering and atmospheric science. At PSE my research quantifies the air quality, health, and equity dimensions of energy production and use. I am an author on over twenty peer-reviewed publications that cover topics related to emissions, air quality, and the impacts of air pollution on human health.

I have used a range of air quality models for different applications in my professional experience. During my postdoctoral training I ran chemical-transport models to evaluate the impacts of different energy sectors on air quality and human health and worked on several projects that aimed to improve the representation of aerosol chemistry in chemical-transport models. At PSE, I have worked on projects that used reduced-form (including InMAP and COBRA) and dispersion modeling.

While at PSE, I have also conducted health and equity analyses of utility decision-making processes, including for several proposed integrated resource plans. As part of this work, I have given and written expert testimony and authored a report on the air quality impacts of individual power plants in the utility's portfolio using very similar approaches to what I used in this testimony.

Q: Have you ever testified before this Commission?

A: Yes. I provided testimony in the Consumers Energy Integrated Resource Plan docket, Case No. U-21090.

Q: Are you sponsoring any exhibits?

A: Yes. I am sponsoring the follow exhibits:

- Exhibit CEO-14: Resume of Dr. Kelsey Bilsback
- Exhibit CEO-15: CEO Emissions Analysis
- Exhibit CEO-16: CEO Health Analysis
- Exhibit CEO-17: CEO Equity Analysis

II. <u>Purpose and Summary</u>

Q: What is the purpose of your Testimony?

A: The purpose of my testimony is to quantify the public health and equity dimensions of power plants in the DTE Electric Company's ("DTE" or "Company") Integrated

Resource Plan ("IRP"). Specifically for the Proposed Course of Action ("PCA"), I: (1) estimate the fine particulate matter ($PM_{2.5}$)-related health impacts of the coal plants included in the utility's portfolio; (2) discuss the equity implications of all fossil-fuel power plants included in the utility's portfolio; (3) discuss additional environmental concerns related to DTE's coal plants; and (4) critique the Company's health and environmental justice analysis as presented in the testimony of Company Witness Marietta.

Q: Please summarize your conclusions.

A: My conclusions are summarized below:

- *Both the Monroe and Belle River coal plants have substantial health impacts.* The only way to completely eliminate the health impacts of these plants is to rapidly transition to zero-emission energy resources (e.g., energy efficiency, demand response, energy storage, solar, and wind).
- *DTE should transition away from coal as soon as possible.* Not prioritizing the retirement of coal power plants will continue to incur substantial health and environmental impacts. In 2023 alone, I estimate that operating the Belle River Units 1 and 2 with coal leads to 72-162 $PM_{2.5}$-related moralities and $796 million-$1.79 billion in total health costs; operating Monroe Units 1 and 2 with coal leads to 13-29 $PM_{2.5}$-related mortalities and $144-$324 million in total health costs; and operating Monroe Units 3 and 4 with coal leads to 15-33 $PM_{2.5}$-related premature mortalities and $162-$366 million in total health costs. While ending coal use in Belle River Units 1 and 2 by 2026 and Monroe Units 3 and 4 by 2028 is a benefit of the PCA, I also recommend moving up the retirement date up of the Monroe 1 and

2 coal units to 2030 from 2035; this earlier retirement would have substantial health benefits, saving 68-154 lives and $777 million-$1.75 billion in $PM_{2.5}$-related health impacts across five years. Further, I recommend the Commission require the Company to review their coal operations every year between now and when all coal units are retired with the aim of reducing coal operations as much as is practical. Assuming that emissions factors of Belle River are constant as a function of load, scaling down Belle River's use by even 10% could save approximately 7-16 lives and $79.6-$180 million in total health costs in 2023.

- *DTE does not have a clear plan to address the impacts of all facilities that are in Environmental Justice (EJ) communities.* It is unclear how the EJ analysis performed by the Company was incorporated into IRP decision-making. Witness Marietta discusses plans to retire the River Rouge Power Plant and a portion of the Northeast Peakers (11-1), which are located in EJ communities and points out that lowering emissions across the portfolio will improve air quality in EJ communities. However, it was unclear from Witness Marietta's testimony how the analysis was used to *inform* decisions making or how DTE plans to reduce or offset the burden of the other power plants that they identify as being located in EJ communities (i.e., *all* Northeast Peaker Units, Delray Peakers, and Superior Peakers). In future IRP, the Commission must require Michigan utilities to perform a more robust and actionable EJ analysis.

III. <u>Emissions and Health Impacts</u>

Q: What are the public health hazards, risks, and impacts associated with fossil fuel combustion in power plants?

A: Fossil-fueled power plants emit air pollutants that impact air quality and are harmful to human health. These include primary air pollutants, i.e., pollutants that are emitted directly by a power plant, and secondary air pollutants i.e., pollutants that are formed chemically in the atmosphere downwind from a power plant. Primary air pollutants from power plants include fine particulate matter ("$PM_{2.5}$"), nitrogen oxides ("NO_x"), sulfur dioxide ("SO_2"), and volatile organic compounds ("VOCs"). NO_x, SO_2, and VOCs are $PM_{2.5}$ precursors, meaning they may chemically react to form $PM_{2.5}$, as a secondary air pollutant, in the atmosphere, while NO_x and VOCs are ozone precursors.

When inhaled, air pollution can cause a range of negative respiratory, cardiovascular, and neurological health impacts.[1] SO_2, NO_x, $PM_{2.5}$, and ozone are Criteria Air Pollutants that are regulated by the U.S. Environmental Protection Agency ("EPA"), due to their impacts on human health.[2] Certain populations such as children, the elderly, and people with underlying health conditions (e.g., asthma) are particularly susceptible to the impacts of air pollution.[3] Further, power plants tend to be disproportionately located in low-income communities and communities of color, leading to high environmental burdens on communities that are already overburdened with other air-polluting sources, such as industry and traffic.[4] Due to these compounding vulnerabilities, these communities are

[1] Murray, C. J., Aravkin, A. Y., Zheng, P., Abbafati, C., Abbas, K. M., Abbasi-Kangevari, M., ... & Borzouei, S. (2020). Global burden of 87 risk factors in 204 countries and territories, 1990–2019: a systematic analysis for the Global Burden of Disease Study 2019. *The Lancet*, *396*(10258), 1223-1249. https://doi.org/10.1016/S0140-6736(20)30752-2

[2] More information about Criteria Air Pollutants from the U.S. EPA: https://www.epa.gov/criteria-air-pollutants

[3] Health effects of Air Pollution: https://www.epa.gov/air-research/research-health-effects-air-pollution#:~:text=for%20Air%20Pollutants-,Health%20Effects%20of%20Air%20Pollutants%20on%20Vulnerable%20Populations,existing%20heart%20and%20lung%20disease.

[4] Power plants and Environmental Justice: https://www.epa.gov/airmarkets/power-plants-and-neighboring-communities

also more likely to experience worse health outcomes in response to air pollutant exposures.

Q: How did you evaluate the health impacts of the coal power plants in DTE's IRP?

A: I used two models to evaluate the health impacts of DTE's coal plants. The first was the U.S. EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (which is called COBRA for short).[5] This model was first released in 2001, has a significant precedent for being used in policies and decision-making processes, and is used widely in the scientific literature.[6] The second model that I used was the Intervention Model for Air Pollution, or InMAP, which has been published in peer-review scientific literature and is also a widely used application.[7]

Both COBRA and InMAP take in information about emissions (e.g., $PM_{2.5}$, NO_x, SO_2, and VOCs) and physical information about a source (e.g., stack height, fuel type) and run a series of calculations to convert changes in emissions to marginal changes in atmospheric (or outdoor) $PM_{2.5}$. These calculations account for the evolution of air pollution in the atmosphere, including whether emissions react chemically to form new pollutants, and to what extent emissions are transported downwind before they are deposited back onto the earth's surface. Both models then convert the marginal changes

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[5] COBRA information page: https://www.epa.gov/cobra
[6] List of publications that cite COBRA: https://www.epa.gov/system/files/documents/2021-10/cobra-publications_9.14.21.pdf
[7] Tessum, C. W., Hill, J. D., & Marshall, J. D. (2017). InMAP: A model for air pollution interventions. *PloS One*, 12(4), e0176131. https://doi.org/10.1371/journal.pone.0176131

in atmospheric $PM_{2.5}$ into health incidences and monetary impacts using epidemiological relationships[8,9] from the peer-reviewed literature.

Q: Why did you use two different health impact models?

A: I chose to run two models because each model has different advantages. COBRA provides estimates of more health endpoints but has lower spatial granularity (estimates are given at the county level). In contrast, InMAP provides increased spatial granularity (up to 1 km resolution) but provides information about fewer health endpoints. Therefore, using COBRA and InMAP together provide a more complete picture of the magnitude and distribution of the health impacts.

Q: Are there any health impacts that COBRA and InMAP models do not account for?

A: Both COBRA and InMAP capture atmospheric $PM_{2.5}$-related health impacts. However, these models underestimate the total health impacts of the power plants, because there are several other pathways in which power plants impact human health. For example, these models do not capture the direct impacts of volatile organic compounds ("VOCs"), many of which are identified as hazardous air pollutants ("HAPs") by the U.S. EPA.[10] These models also do not capture the impacts of ozone, which forms through atmospheric reactions of precursors such as VOCs and NO_x, both of which are emitted by coal plants

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[8] Krewski, D., Jerrett, M., Burnett, R. T., Ma, R., Hughes, E., Shi, Y., ... & Tempalski, B. (2009). Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. *Res Rep Health Eff Inst* (140), 5-114; discussion 115-136.

[9] Lepeule, J., Laden, F., Dockery, D., & Schwartz, J. (2012). Chronic exposure to fine particles and mortality: an extended follow-up of the Harvard Six Cities study from 1974 to 2009. *Environmental Health Perspectives*, *120*(7), 965-970.

[10] More information about Hazardous Air Pollutants: https://www.epa.gov/haps

(see Table 1).[11,12] Further, COBRA and InMAP do not capture the health impacts of other factors such as the on-site disposal of toxic materials (see Section V); therefore the public health impacts estimated using COBRA and InMAP likely underestimate the total health impacts of DTE's coal plants.

Still, while the models do not capture *all* the health impacts associated with coal plants, they provide important information about the $PM_{2.5}$-related impacts of power plants, which is the dominant pathway in which coal power plants impact human health, and how the impacts of the plants are distributed spatially.

Q: What is the magnitude of total pollutants emitted and what are the emissions rates from the coal plants in the DTE IRP?

A: The *total* emissions (tons) of the two coal plants included in DTE's PCA (Portfolio #2) for 2023 are included in Table 1. Emissions data from 2023 through 2042 for the two coal plants are in Exhibit CEO-15. These emissions are for the year 2023 from Witness Marietta's workpapers (BJM-1), who testified on the equity and health impacts of DTE's PCA. Generation data (GWh) is from Witness Manning's workpapers for the PCA. Emissions *rates* (tons/GWh) are estimated by dividing the 2023 emissions by the 2023 annual generation for each plant.

[11] Lelieveld, J., Evans, J. S., Fnais, M., Giannadaki, D., & Pozzer, A. (2015). The contribution of outdoor air pollution sources to premature mortality on a global scale. *Nature*, 525(7569), 367-371. https://doi.org/10.1038/nature15371

[12] Murray, C. J., Aravkin, A. Y., Zheng, P., Abbafati, C., Abbas, K. M., Abbasi-Kangevari, M., ... & Borzouei, S. (2020). Global burden of 87 risk factors in 204 countries and territories, 1990–2019: a systematic analysis for the Global Burden of Disease Study 2019. *The Lancet*, *396*(10258), 1223-1249. https://doi.org/10.1016/S0140-6736(20)30752-2

Table 1: Total annual emissions per year of carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), and volatile organic compounds (VOCs) in short tons. Belle River Unit 1 and 2 emissions are only for DTE's emissions, not the emissions from the entire plant, as DTE owns approximately 81% of the plant and the remaining 19% is owned by the Michigan Public Power Agency.

Plant Name	**Fuel Type**	**Generation** *GWh*	**CO_2** *tons*	**NO_x** *tons*	**SO_2** *tons*	**$PM_{2.5}$** *tons*	**VOCs** *tons*
Belle River Units 1 & 2	**Coal**	6,069	6,468,063	6,165	18,184	33	101
Monroe Units 1 & 2	**Coal**	6,646	6,987,238	1,966	1,080	164	17
Monroe Units 3 & 4	**Coal**	8,713	9,093,586	2,556	1,264	155	22

Table 2: Annual emissions per MWh of carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), and volatile organic compounds (VOCs). Belle River Unit 1 and 2 emissions are only for DTE's emissions, not the emissions from the entire plant.

Plant Name	**Fuel Type**	**CO_2** *tons/GWh*	**NO_x** *tons/GWh*	**SO_2** *tons/GWh*	**$PM_{2.5}$** *tons/GWh*	**VOCs** *tons/GWh*
Belle River Units 1 & 2	**Coal**	1,066	1.02	3.0	0.005	0.017
Monroe Units 1 & 2	**Coal**	1,051	0.30	0.16	0.025	0.003
Monroe Units 3 & 4	**Coal**	1,044	0.29	0.15	0.018	0.003

Q: What are your findings with respect to emissions?

A: Both coal plants emit health-damaging air pollutants. Belle River Units 1 and 2 have higher total NO_x and SO_2 emissions and emissions rates than either Monroe Units 1 and 2 or Monroe Units 3 and 4. These differences are likely due to the significantly less effective SO_2 and NO_x emissions controls that Belle River Units 1 and 2 are outfitted with. According to data from 2018-2022 in the U.S. EPA's Clean Air Markets Program Data ("CAMPD")[13], Monroe Units 1-4 have wet limestone scrubbers, which remove SO_2, and selective catalytic reduction and low NO_x cell burners, which remove NO_x. In contrast, Belle River only has low NO_x burner technology and CAMPD reports no SO_2 controls. I also found that Monroe Units 1 and 2 and Monroe Units 3 and 4 both have higher total $PM_{2.5}$ emissions and emissions rates than Belle River 1 and 2, despite both Monroe and Belle River reporting the same PM control technology in CAMPD, all units report using an electrostatic precipitator.

Q: Did DTE conduct a health impact assessment in their IRP testimony? Can you summarize the analysis?

A: Yes, Witness Marietta provided a health impact assessment on behalf of DTE. To my understanding, Witness Marietta used COBRA to present the *change* in $PM_{2.5}$-related health incidences and monetary value due to emissions reductions over the twenty-year timeframe (between 2023 and 2042) of each of the five portfolios presented in his testimony, including the PCA. Witness Marietta identified that the $PM_{2.5}$-related health impacts would decrease over the course of the PCA, due to emissions reductions.

Q: What is missing from DTE's assessment?

A: DTE's public health analysis fails to provide the context necessary to evaluate the health impacts of each portfolio. DTE should have presented the *absolute* impacts of each of the portfolios, not only the relative difference in health impacts over the course of each of the portfolios. For example, the absolute impacts of individual plants or the overall fleet

[13] U.S. EPA's Clen Air Markets Program Data: https://campd.epa.gov/

should be presented in an example year (e.g., Table 3 below) and cumulatively over the course of the portfolio (e.g., Table 4 below). If only the change in health impacts between years or portfolios are presented, then it is impossible to ascertain actual health impacts that the utility's portfolio has on a community. Below, I present an alternative approach to DTE's health impact assessment. My approach includes the absolute annual and cumulative health impacts, rather than the impacts over the course of the PCA. Going forward, the Commission should require DTE to perform a similar analysis which measures both absolute annual and cumulative health impacts.

Q: What are the annual public health impacts of DTE's coal plants?

A: A summary of the annual (2023) $PM_{2.5}$-related health impacts from the Belle River and Monroe coal plants calculated using COBRA are given in Table 3. COBRA was run using the total emissions reported in Witness Marietta's workpapers (BJM-1) for the two coal plants (Portfolio #2) and stack metrics were from the U.S. Energy Information Administration.[14] The full report of metrics given by COBRA are in Exhibit CEO-16. I found that both coal plants lead to substantial premature mortalities, respiratory and cardiovascular impacts, and monetary impacts. The ranges given in Table 3 represent the "low" and "high" estimates from COBRA, which are derived from two different health-impact functions that capture some of the uncertainty associated with the relationship between $PM_{2.5}$ and health impacts.

[14] https://www.eia.gov/electricity/data/eia860/

Table 3: Annual national public health impacts of DTE's coal power plants in 2023. Values are in instances or dollars per year. Estimates are from COBRA using a 3% discount rate for the monetized health impacts. Emissions used in the model are from 2023 in Witness Marietta's workpapers (BJM-1) (Portfolio #2).

	Belle River Units 1 & 2 2023 Coal	**Monroe Units 1 & 2 2023 Coal**	**Monroe Units 3 & 4 2023 Coal**
Total Health Costs	$796 million- $1.79 billion	$144 million- $324 million	$162 million- $366 million
Mortalities	72-162	13-29	15-33
Upper Respiratory Symptoms	1,441	272	307
Asthma Exacerbation	1,510	282	319
Work Loss Days	7,437	1,344	1,519

A summary of the cumulative $PM_{2.5}$-related health impacts from the Belle River and Monroe coal plants (calculated with COBRA) are given in Table 4. The cumulative impacts are the total impacts calculated over the duration of the portfolio, using the emissions that were provided by Witness Marietta. The cumulative impacts of the Belle River coal plant are presented between 2023 and 2026, since one unit of Belle River may be at least partially operating on coal during that time. In addition to providing the cumulative impacts of Monroe Units 1 and 2 and Units 3 and 4 across the proposed plant lifetime, I also provide the emissions of Monroe Units 1 and 2 between 2031 and 2035 to evaluate the health benefits of retiring Monroe Units 1 and 2 in 2030 rather than 2035.

Table 4: Cumulative national public health impacts of DTE's coal power plants. Values are in instances or dollars per year. Estimates are from COBRA using a 3% discount rate for the monetized health impacts. Emissions used in the model are from Witness Marietta's work papers (BJM-1) (Portfolio #2).

	Belle River Units 1 & 2 2023-2026 Coal	**Monroe Units 3 & 4 2023-2028 Coal**	**Monroe Units 1 & 2 2023-2035 Coal**	**Monroe Units 1 & 2 2031-2035 Coal**
Total Health Costs	\$2.51 billion - \$5.66 billion	\$804 million -\$1.81 billion	\$2.09 billion -\$4.71 billion	\$777 million -\$1.75 billion
Mortalities	225-510	71-162	184-416	68-154
Upper Respiratory Symptoms	4,535	1,505	3,885	1,437
Asthma Exacerbation	4,738	1,544	3,951	1,453
Work Loss Days	23,270	7,232	18,276	6,666

Q: Can you summarize the health impact of DTE's coal plants and how retiring these coal plants will benefit public health?

A: Operating Belle River Units 1 and 2 incurs significant $PM_{2.5}$-related health impacts, approximately five times the $PM_{2.5}$-related health impacts of either Monroe Units 1 and 2 or Monroe Units 3 and 4 per year (in 2023). The impacts of operating Belle River are much higher due to less stringent SO_2 and NO_x emissions controls. Between 2023 and 2026 I estimate that operating Belle River's Units 1 and 2 with coal will lead to 225-510 $PM_{2.5}$-related premature mortalities and \$2.51-\$5.66 billion in health impacts (Table 4). Based on the emissions projections from Witness Marietta's workpapers, the years with the largest health impacts are 2023 and 2024, with the health impacts decreasing by about half every year between 2024 through 2026. This may be because the plant will burn less coal as DTE prepares to repower Belle River with gas.

Additionally, I estimate that operating Monroe Units 3 and 4 between 2023 and 2028 will lead to 71-162 $PM_{2.5}$-related premature mortalities and incur \$804 million-\$1.81 billion in $PM_{2.5}$-related health costs (Table 4). Retiring Monroe Units 3 and 4 in 2028, as outlined in DTE's PCA, will save approximately 10-30 lives each year that the coal plant is not operating,[15] depending on the projected emissions and health impact function used in the calculation.

Further, I estimate that operating Monroe Units 1 and 2 on coal as outlined in the PCA will lead to 184-416 $PM_{2.5}$-related mortalities \$2.09 -\$4.71 billion in health costs between 2023 and 2035. In the current PCA, Monroe Units 1 and 2 have a retirement date of 2035. Moving up the retirement date for Monroe 1 and 2 to 2030 would have substantial health benefits, saving 68-154 lives and \$777 million-\$1.75 billion in health impacts across five years (Table 4).

Given the substantial health impacts of utilizing coal power, I recommend that DTE prioritize scaling down coal-based energy production or retiring their coal plants entirely. For example, assuming that the emissions factors of Belle River are constant as a function of load, scaling down Belle River's use by even 10% could save approximately 7-16 lives and \$79.6-\$180 million in health impacts in 2023. To achieve this, DTE could consider running their coal plants more economically, running the plants on a seasonal basis, or buying grid power instead.

[15] Prior to this case the plant was scheduled to close in 2039. *See* Direct Testimony of Joyce E. Leslie at 14.

Q: What are the annual and cumulative public health impacts of DTE's proposed Belle River Unit 1 and 2 gas repower?

A: A summary of the annual (2027) and cumulative (2027-2039) $PM_{2.5}$-related health impacts of repowering Belle River Units 1 and 2 with gas is given in Table 5. I present the annual impacts for 2027 and the cumulative impacts for 2027 onward, since this marks the first year that Belle River will be powered completely with gas.

Table 5: Annual and cumulative national public health impacts of repowering Belle River Units 1 and 2 with gas in 2027. Values are in instances or dollars per year. Estimates are from COBRA using a 3% discount rate for the monetized health impacts. Emissions used in the model are from Witness Marietta's workpapers (BJM-1) (Portfolio #2).

	Belle River Units 1 & 2 2027 Gas	**Belle River Units 1 & 2 2027-2039 Gas**
Total Health Costs	\$14.5 million - \$32.8 million	\$135 million - \$304 million
Mortalities	1.3-2.9	12-27
Upper Respiratory Symptoms	25	229
Asthma Exacerbation	25	231
Work Loss Days	119	1,101

Comparing the health impacts of Belle River Units 1 and 2 when they are running on coal in 2023 to the health impacts of Belle River Units 1 and 2 are running on gas in 2027, I estimate running Belle River on gas will save 71-159 $PM_{2.5}$-related mortalities per year. However, between 2027 and 2039 operating Belle River as a gas plant will still contribute 12-27 excess deaths and \$135-\$304 million dollars in health-related costs.

Q: How are these health impacts distributed spatially?

A: Maps showing the spatial distribution of the public health impacts of the two coal power plants outlined are given below in Figure 1. This figure illustrates where the health impacts are most likely to occur due to the transport and chemistry of $PM_{2.5}$ in the atmosphere. Figure 1 shows both the *total* health impacts and the *per capita* health impacts. The largest total impacts tend to be in the more densely populated areas, while the largest per-capita health impacts are near and directly downwind of the plants because that is where the emissions from each plant tend to impact air quality the most. Figure 1 demonstrates that $PM_{2.5}$ may stay suspended in the atmosphere for an extended period, traveling long distances downwind in the process. While the Belle River and Monroe power plants impact air quality in the state of Michigan, they also impact air quality and health downwind across the Northeastern states. These coal plants will also lead to adverse $PM_{2.5}$-related health impacts in Canada, although the results are not captured in the COBRA or InMAP models.

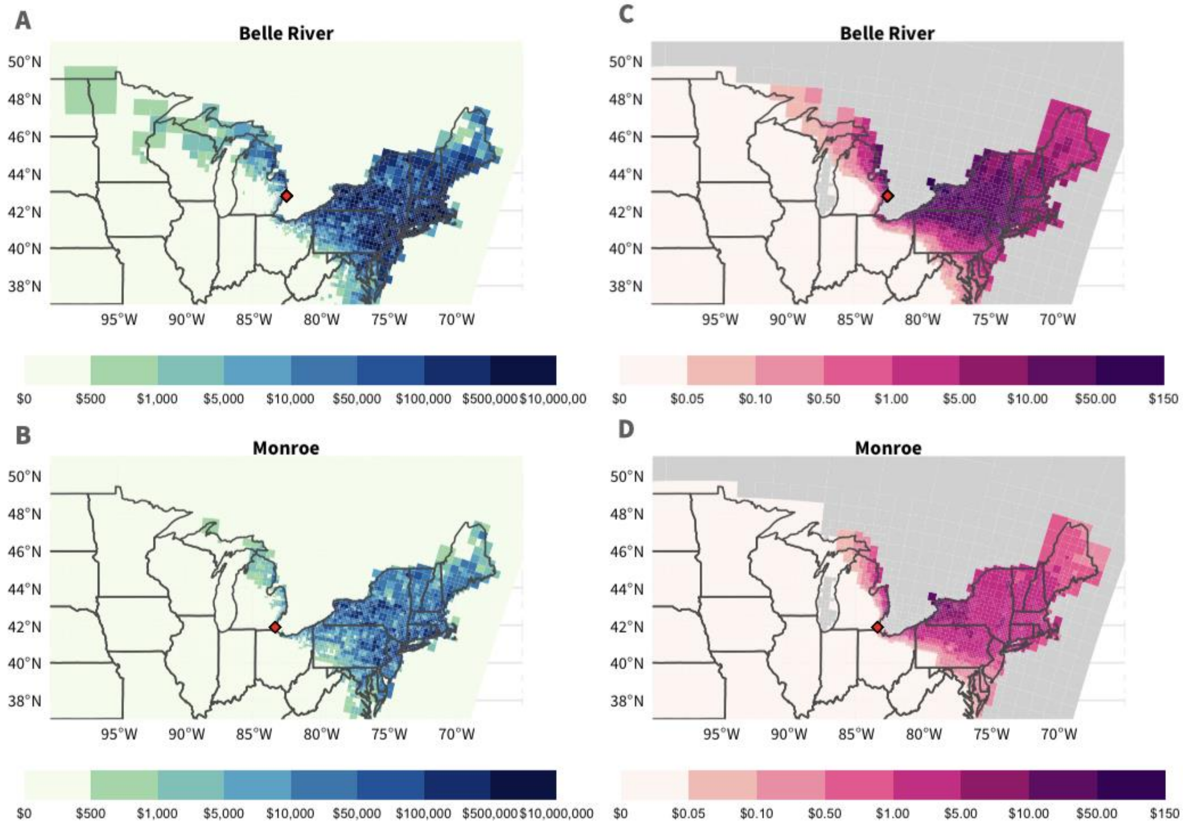

Figure 1: Total ($) (A and B) and per capita ($ per capita) (C and D) annual public health impacts of Belle River and Monroe. Emissions are from 2023. The location of each plant is shown as a red dot. Health impacts were only evaluated in the contiguous U.S. Data are from InMAP model runs. The analysis only included mortality as a health outcome and did not include a discount rate in the economic valuation.

IV. <u>Equity and Demographics</u>

Q: Who is impacted most by power plants and why?

A: The per-capita impacts of power plants tend to be greatest for people living in close proximity (within several miles) and downwind of a power plant. These impacts can include both stack emissions impacts (as discussed in Section III) as well as other risks (e.g., toxic releases,[16] groundwater contamination, emissions from diesel equipment onsite).

Q: Who lives near DTE's power plants and the power plants with which DTE holds power purchase agreements, and why might these populations be particularly vulnerable to the pollution impacts of these plants?

A: Across the US, low-income communities and communities of color tend to be disproportionately impacted by environmental risk factors and health outcomes, including air pollution from power plants. Since the MiEJScreen tool is only in a draft version and does not yet have the ability to summarize across multiple census tracts (to my knowledge), I used the U.S. EPA's Environmental Justice Screening and Mapping Tool (or EJScreen) to summarize the demographic, socioeconomic, and environmental information provided by EJScreen over a selected area. For this analysis, I used the latitude and longitude values from the U.S. Energy Information Administration's Electricity Data Browser[17] tool and summarized the data over a buffer with a 3-mile radius, which is aligned with the IRP filing requirements and the distance used in the EPA's Power Plants and Neighboring Communities Mapping Tool. While I evaluated and reported all indexes and indicators in my testimony I used the metrics at or above the 75th percentile in the state as a starting point for my testimony.[18] The results of "low-income" and the "people of color" indicators are in Figure 2, and the full results of my analysis are in Exhibit CEO-17.

[16] https://www.epa.gov/toxics-release-inventory-tri-program
[17] https://www.eia.gov/electricity/data.php
[18] Link to the U.S. EPA's Power Plants and Neighboring Communities Mapping Tool https://experience.arcgis.com/experience/2e3610d731cb4cfcbcec9e2dcb83fc94

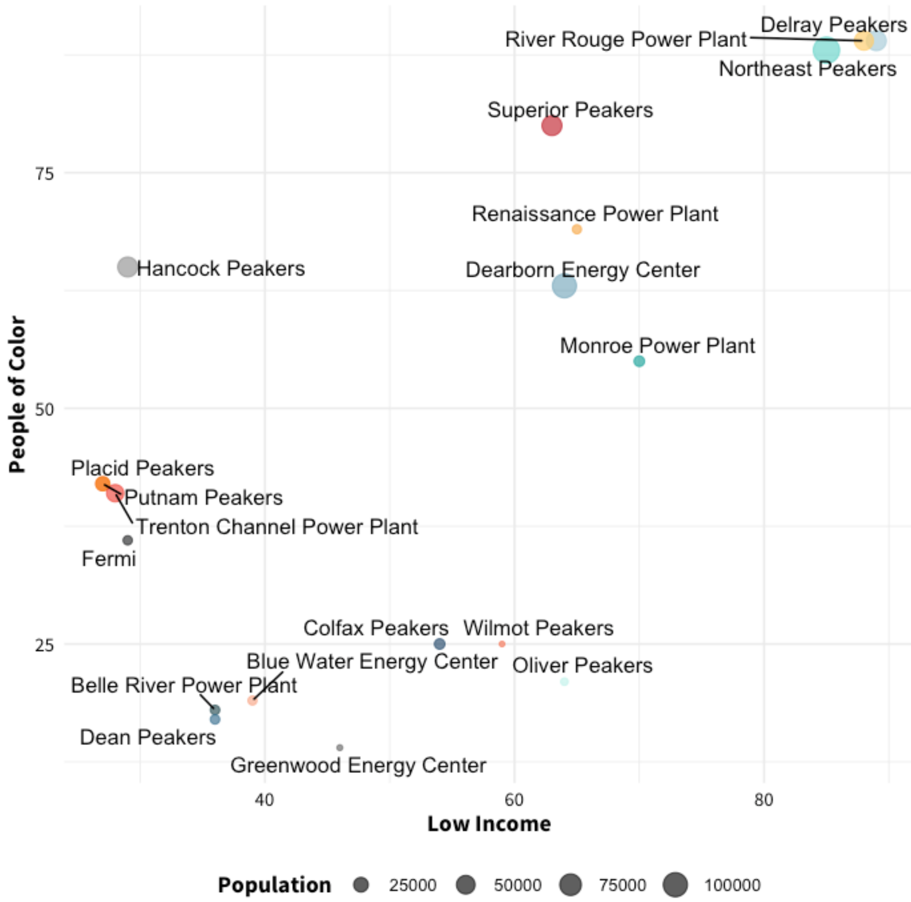

Figure 2: State percentile of low-income population and people of color living within a three-mile radius of each power plant. Size of the circle represents the population living within a three-mile radius of the plant.

Q: Did you use any other equity screening tools to evaluate DTE's power plants?

A: Yes. As a point of comparison with EJScreen, I used the MiEJscreen tool to evaluate the equity metrics in the census tract that each plant is located in and the Council on Environmental Quality's Climate and Economic Justice Screening Tool (CEJST) to evaluate whether each plant was located in a census tract identified as a "disadvantaged community". Results are given in Exhibit CEO-17.

Q: What are your findings from the equity analysis?

A: River Rouge Power Plant, Delray Peakers, Northeast Peakers, and Superior Peakers were >75th percentile for either or both the "low-income" and the "people of color" indicator. Notably, these plants tended to be in areas with larger populations when comparing across plants. In addition to these plants, several other plants had socioeconomic indicators that were >75th percentile for the state. For example, Belle River was in the 83rd percentile for "population over Age 64" and was in the 79th percentile for "limited English speaking". Monroe was also in the 80th percentile for "population under age 5".

I also found that River Rouge Power Plant, Delray Peakers, Northeast Peakers, and Superior Peakers, Dearborn Energy Center, and Monroe had at least one EJ index at or over the 75th percentile in the state and many plants had an environmental indicator at or over 75th percentile (Exhibit CEO-17).

Additionally, Delray Peakers (99th), Monroe (89th), and Trenton Channel Power Plant (77th) were located in census tracts with a MiEJScore over the 75th percentile and Delray, Fermi, Monroe, Northeast, and Oliver were located in census tracts identified as disadvantaged communities using the CEJST tool.

Several of the plants identified as being in disadvantaged communities were peakers (e.g., Delray, Northeast, Superior). While these peakers may not contribute as much to total health impacts, because of lower total stack emissions, they have the potential to contribute to acute air quality issues because they often operate when other plants are running (to meet peak demands) and when the air quality may be generally poor (e.g., high ozone days).[19] Because of this, the health impacts of peaker plants may be underestimated when using models like COBRA and InMAP that only capture health impacts on an annual basis.

Q: Did DTE conduct an equity analysis in the testimony related to their IRP?

A: Yes.

Q: Can you summarize the findings?

A: Witness Marietta provided an environmental justice assessment using EJScreen 2.0 to evaluate the EJ indices of 18 plants within a 3-mile radius of each plant. Witness Marietta identified four facilities as having EJ indexes above the 80th percentile: Delray Peakers, Northeast Peakers, River Rouge Power Plant, and Superior Peakers. In the context of the EJ analysis, Witness Marietta (1) said that a peaker analysis was considered in the IRP modeling and discussed plans for retirement of the River Rouge Power Plant and the Northeast Peaker unit 11-1, (2) mentioned that reducing emissions across DTE's portfolio would generally improve air quality near facilities with an EJ index above the 80th percentile, and (3) discussed how the retirement of Belle River and Monroe would have air quality and environmental benefits (although these plants were not identified as having an EJ index >80th percentile).

Q: How would you improve DTE's EJ analysis?

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[19] Krieger, E. M., Casey, J. A., & Shonkoff, S. B. (2016). A framework for siting and dispatch of emerging energy resources to realize environmental and health benefits: Case study on peaker power plant displacement. Energy Policy, 96, 302-313. https://doi.org/10.1016/j.enpol.2016.05.049

A: The Commission should require a more robust and actionable EJ analysis from DTE and other Michigan utilities. I outline several points where DTE's EJ analysis could be improved below:

- *Include population and environmental and demographic indicators in their equity analysis.* Witness Marietta evaluated EJ indexes but did not evaluate the socioeconomic or environmental indicators that are also provided by EJScreen. Across the US, low-income communities and communities of color tend to be disproportionately impacted by environmental risk factors and health outcomes, including air pollution from power plants; therefore, this information should be considered when evaluating the equity impacts of DTE's portfolio. While this information is included in the EJ index metric, it's also important to evaluate these variables in addition to the number of people living close to each plant. Additionally, there are other socioeconomic indicators that are included in EJScreen, but that are not captured in the EJ index (e.g., unemployment rate, population over age 64), which should be evaluated as well. By evaluating the metrics provided by EJScreen more comprehensively, I identified that several additional plants had indexes or indicators above the 75^{th} percentile (e.g., Monroe, Belle River, Dearborn).
- *Use the MiEJScreen tool and metrics when the tool is finalized.* I recommend that the Company use the MiEJScreen tool in the future to examine census tracts within a 3-mile radius of each plant. Since the tool will be specific to Michigan, the tool will capture elements that the EJScreen tool misses and that are in alignment with Michigan priorities.

Witness Marietta also identified plants as being located in an EJ community if they had at least one EJ index at or above the 80th percentile; however, the EJScreen technical documentation states that the 80th percentile is "simply a starting point" and that additional analysis should be conducted before deciding on a specific threshold.[20,21,22] In the future, I recommend that the Company choose the guidelines suggested in the Michigan tool, because this metric will likely be better aligned with what constitutes an EJ community in Michigan.

- *Use the EJ analysis to inform the PCA.* Finally, I recommend that the Commission require the Company do more to use the EJ analysis they conduct to inform the PCA. Specifically, the Commission must require the Company and other Michigan utilities to identify *how* their EJ analysis informed their IRP application. In his testimony, Witness Marietta discussed (1) plans for retirement of the River Rouge Power Plant and the Northeast Peaker unit 11-1 and (2) that reducing emissions across DTE's portfolio would generally improve air quality near facilities with an EJ index above the 80th percentile. However, DTE could better incorporate their EJ analysis into their IRP by using the analysis to *inform* decisions making in the PCA and should outline more clearly how their EJ analysis resulted in steps to reduce or offset the burden of *all* of the power plants that are identified as being located in EJ communities.

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[20] EJScreen technical documentation: https://www.epa.gov/system/files/documents/2023-01/EJScreen%20Technical%20Documentation%20October%202022.pdf
[21] Comments to the MPSC on the IRP filling requirements: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000004Ga7zAAC
[22] Reply Comments to the MPSC on the IRP filling requirements: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000004PFfxAAG

V. Environmental Hazards

Q: Are there any other environmental hazards that may impact health that were not discussed above?

A: Yes. Reviewing the U.S. EPA's Enforcement and Compliance History Online (ECHO) database,[23] I found that both the Belle River and Monroe power plants have been in violation of the Clean Air Act and the Clean Water within the last three years. These violations demonstrate that DTE may be an unreliable operator. Further, the U.S. EPA recently denied applications for the continued use of unlined coal ash impoundments for both the Belle River Power Plant and Monroe Power Plant, because the owners and operators failed to demonstrate that impoundments complied with current requirements.[24] These findings suggest that significant environmental pollution may need to be mitigated at each facility, and that early retirement of these facilities will reduce the amount of waste being disposed of in coal ash impoundments which pose an outsized environmental health risk to the surrounding communities.

VI. Summary and Recommended Changes

Q: From a public health standpoint, what are the public health risks and benefits of the proposed DTE IRP?

A: I outline the benefits and risks of DTE's IRP below.

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[23] U.S. EPA Enforcement and Compliance History Online (ECHO) database: https://echo.epa.gov/
[24] https://www.epa.gov/newsreleases/epa-announces-latest-actions-protect-groundwater-and-communities-coal-ash

Benefits:

1. *Ending coal operations at Belle River Units 1 and 2.* The Belle River coal plant will incur significant health impacts every year the plant is operating. I view prioritizing the transition of the Belle River Units 1 and 2 off of coal by 2026 as a benefit. Comparing emissions in 2023 when Belle River Units 1 and 2 are running on coal to 2027 when Belle River Units 1 and 2 are running on gas, the $PM_{2.5}$-related mortalities will be reduced by 71-159 lives. However, if Belle River is converted to gas, it will continue to lead to health impacts, but the health impacts will be much lower compared to when the plant is operated with coal. I estimate that when Belle River Units 1 and 2 are operating with gas they will lead to 12-27 mortalities and $135-$304 million in total health costs between 2027 and 2039.
2. *Retiring Monroe Units 3 and 4.* Operating Monroe Units 3 and 4 with coal also leads to substantial health impacts. Prioritizing the retirement of Monroe units 3 and 4 in 2028 as outlined in DTE's PCA will save approximately 10-30 lives per year, depending on the projected emissions and health impact function used in the calculation.

Risks:

1. *Staying on coal any longer than absolutely necessary.* As outlined in my testimony, burning coal leads to substantial emissions and health and environmental impacts. Not prioritizing the retirement of DTE’s coal power plants will continue to incur health impacts. For example, in 2023 alone, I estimate that operating the Belle River Units 1 and 2 with coal leads to 72-162 $PM_{2.5}$-related moralities and $796 million-$1.79 billion in total health costs; operating Monroe Units 1 and 2 with coal

leads to 13-29 $PM_{2.5}$-related mortalities and $144-$324 million in total health costs; and operating Monroe Units 3 and 4 with coal leads to 15-33 $PM_{2.5}$-related premature mortalities and $162-$366 million in total health costs. Switching to natural gas reduces but does not eliminate these health impacts, while a cleaner portfolio could eliminate such impacts entirely.

2. *Not having a clear plan to address the impacts of all facilities located in EJ communities.* As outlined in my testimony, the Company has not outlined a clear plan to address or offset the impacts of the power plants that were identified as being located in EJ communities (i.e., regions having EJScores above the 80th percentile). While Witness Marietta discusses plans to retire the River Rouge Power Plant and a portion of Northeast Peakers (11-1) and mentions that reducing emissions across the portfolio will benefit EJ communities, there is no plan to address the impacts of the Northeast Peaker Units, Delray Peakers, or Superior Peakers, which are located in EJ communities as identified by Witness Marietta The Commission should require Michigan utilities to apply the findings from an EJ analysis to inform the PCA and clearly outline how the EJ analysis was translated to actionable outcomes.

Q: Dr. Bilsback, do you recommend any changes to DTE's IRP proposal?

A: The Belle River and Monroe coal plants lead to significant $PM_{2.5}$ health impacts for every year they are operational. I recommend retiring Monroe's Units 1 and 2 from coal in 2030 instead of 2035. Retiring Monroe Units 1 and 2 five years earlier will have substantial health benefits, saving 68-154 lives and $777 million-$1.75 billion in health costs. Additionally, I recommend that the Commission require DTE to prioritize scaling down coal-based energy production by running their coal plants more economically, running the plants on a seasonal basis, or buying grid power instead. For example, assuming that the emissions factors of Belle River are constant as a function of load, scaling down Belle River Unit 1 and 2's use by even 10% could save 7-16 lives in 2023 and $79.6-$180 million in health impacts. To implement this, I recommend the Commission consider requiring the Company to review the operation of coal resources every year between now and when all coal units are retired to reduce coal operations as much as is practical.

Q: Is there anything else you would like to add to your testimony?

A: Air pollution from burning fossil fuels has significant respiratory, cardiovascular, and neurological impacts. Mounting scientific evidence suggests that air pollution can cause health impacts at very low atmospheric concentrations, which is leading the U.S. EPA to consider revising the National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$.[25] The more quickly DTE transitions to a cleaner portfolio, the more quickly the public health impacts of energy production from fossil fuels can be mitigated.

Q: Does this complete your testimony?

A: Yes.

[25] https://www.epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm

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Personal Statement

Dr. Bilsback is a scientist with a background in mechanical engineering and atmospheric science. She has expertise in energy, combustion, air pollution, aerosols, atmospheric modeling, emissions measurements, the impacts of air pollution on human health and climate, and data and statistical analyses. Her work uses modeling to evaluate the impacts of energy production and use on air quality and human health. Prior to joining PSE, Dr. Bilsback was a postdoctoral researcher in atmospheric science at Colorado State University. As a researcher, she implemented process-level models for secondary organic aerosol into regional atmospheric models and used chemical-transport models to assess the air quality, health, and climate impacts of energy transition policies. During her PhD, Dr. Bilsback studied solid-fuel cookstove emissions and their impacts on air quality, health, and climate. During this time, she developed a novel laboratory test protocol for solid-fuel cookstoves used to study various aspects of cookstove emissions in two large-scale laboratory campaigns. She also utilized low-cost sensors to quantify the cookstove emissions during several field campaigns in Uganda, India, China, and Honduras. Education

Doctorate of Philosophy in Mechanical Engineering **2013-2018**
Colorado State University, Fort Collins, CO, USA

Bachelor of Arts in Physics (Minor: Mathematics) **2009-2013**
Boston University, Boston, MA, USA

Technical Experience

Senior Scientist at PSE Healthy Energy **Aug. 2021-Present**
Oakland, CA, USA

- Technical project lead on research efforts to design and build a public-facing web portal that communicates the air quality and health risks associated with satellite-sensed methane loss-of-containment events.
- Developing air quality modeling systems and capabilities including indoor and outdoor air quality models to evaluate the impacts of energy production and use on air quality and human health.

Postdoctoral Researcher in Atmospheric Science **2018-2021**
Colorado State University, Fort Collins, CO, USA

- Configured, utilized, and developed global chemical-transport models (GEOS-Chem, WRF-Chem) to evaluate the air quality, health and climate impacts of international air-pollution-control policies.
- Worked with process-level models for secondary organic aerosol (SOA) that explicitly model the chemistry, thermodynamics, and microphysics of SOA (simpleSOM-MOSAIC).

Graduate Student Researcher in Mechanical Engineering **2013-2018**
Colorado State University, Fort Collins, CO, USA

- Characterized the climate and health-relevant properties of smoke from solid-fuel cookstoves using a custom-built portable air pollution sampler during field campaigns.
- Designed and executed large-scale laboratory-based studies to measure the climate and health relevant properties of smoke emitted by a variety of stove technologies.
- Developed statistical models and conducted analysis of large datasets.

Refereed Publications

h-index: 10, i-index: 10

22. Gordon, J., **Bilsback, K. R.**, Fiddler, M. N., Pokhrel, R. P., Fischer, E. V., Pierce, J. R., & Bililign, S. (2023). The Effects of Trash, Residential Biofuel, and Open Biomass Burning Emissions on Local and Transported $PM_{2.5}$ and its Attributed Mortality in Africa. *GeoHealth*. https://doi.org/10.1029/2022GH000673

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19. Karambelas, A., Fiore, A. M., Westervelt, D. M., McNeill, V. F., Randles, C. A., Venkataraman C., Pierce, J. R., **Bilsback, K. R.**, & Milly, G. P. (2022). Investigating drivers of particulate matter pollution over India and the implications for radiative forcing with GEOS-Chem-TOMAS15. *Journal of Geophysical Research: Atmospheres*. https://doi.org/10.1029/2021JD036195

18. Zhao, J., Ma, W., **Bilsback, K. R.**, Pierce, J. R., Zhou, S., Chen, Y., Yang, G., & Zhang, Y. (2022). Simulating the radiative forcing of oceanic dimethylsulfide (DMS) in Asia based on machine learning estimates. *Atmospheric Chemistry and Physics*, 22, 9583–9600. https://doi.org/10.5194/acp-2022-3

17. O'Dell, K., **Bilsback, K.**, Ford, B., Martenies, S. E., Magzamen, S., Fischer, E. V., & Pierce, J. R. (2021). Estimated mortality and morbidity attributable to smoke plumes in the United States: Not just a western US problem. *GeoHealth*, *5*(9), e2021GH000457. https://doi.org/10.1029/2021GH000457

16. Jathar, S. H., Cappa, C. D., He, Y., Pierce, J. R., Chuang, W., **Bilsback**, **K. R.**, Seinfeld, J. H., Zaveri, R. A., & Shrivastava, M. (2021). A computationally efficient model to represent the chemistry, thermodynamics, and microphysics of secondary organic aerosols (simpleSOM): model development and application to α-pinene SOA. *Environmental Science: Atmospheres*, *1*(6), 372-394. https://doi.org/10.1039/D1EA00014D

15. Croft, B., Martin, R. V., Moore, R., Russell, L., Saliba, G., Marti Gali, M., Chang, R., **Bilsback, K. R.**, Kodros, J. K., & Pierce, J. R. (2021) Factors controlling marine aerosol size distributions and their climate effects over the Northwest Atlantic Ocean region. *Atmospheric Chemistry and Physics*, 21(3), 1889-1916. https://doi.org/10.5194/acp-21-1889-2021

14. Stolz, D. C., **Bilsback, K. R.**, Pierce, J. R., & Rutledge, S. A. (2021). Evaluating empirical lightning parameterizations in global atmospheric models. *Journal of Geophysical Research: Atmospheres*, *126*(4), e2020JD033695. https://doi.org/10.1029/2020JD033695

13. **Bilsback, K. R.**, Kerry, D., Carter, E., Croft, B., Ford, B., Martin, R. V., & Pierce, J. R. (2020). Beyond SO_x reductions from shipping: assessing the impact of NO_x and carbonaceous-particle controls on human health and climate. *Environmental Research Letters*, *15*(12), 124046. https://doi.org/10.1088/1748-9326/abc718

12. Emerson, E. W., Hodshire, A. L., DeBolt, H. M., **Bilsback, K. R.**, Pierce, J. R., McMeeking, G. R., & Farmer, D. K. (2020). Revisiting particle dry deposition and its role in radiative effect estimates. *Proceedings of the National Academy of Sciences*, *117*(42), 26076-26082. https://doi.org/10.1073/pnas.2014761117

11. **Bilsback, K. R.**, Baumgartner, J., Cheeseman, M., Ford, B., Kodros, J. K., Li, X., Ramnarine, E., Tao, S., Zhang, Y., Carter, E., & Pierce, J. R. (2020). Estimated aerosol health and radiative effects of the residential coal ban in the Beijing-Tianjin-Hebei Region of China. *Aerosol and Air Quality Research*, *20*(11), 2332-2346. https://doi.org/10.4209/aaqr.2019.11.0565

10. Jathar, S. H., Sharma, N., **Bilsback, K. R.**, Pierce, J. R., Vanhanen, J., Gordon, T. D., & Volckens, J. (2020). Emissions and radiative impacts of sub-10 nm particles from biofuel and fossil fuel cookstoves. *Aerosol Science and Technology*, *54*(10), 1231-1243. https://doi.org/10.1080/02786826.2020.1769837

9. Piedrahita, R., Johnson, M., **Bilsback, K. R.**, L'Orange, C., Kodros, J. K., Eilenberg, S. R., Naluwagga, A., Shan, M., Sambandam, S., Clark, M., Reynolds, B., Pierce, J. R., Balakrishnan, K., Robinson, A. L. & Volckens, J. (2020). Comparing regional stove-usage patterns and using those patterns to model indoor air quality impacts. *Indoor air*, *30*(3), 521-533. https://doi.org/10.1111/ina.12645

8. Benka-Coker, M. L., Peel, J. L., Volckens, J., Good, N., **Bilsback, K. R.**, L'Orange, C., Quinn, C., Young, B. N., Rajkumar, S., Wilson, A., Tryner, J., Africano, S., Osorto, A. B., & Clark, M. L. (2020). Kitchen concentrations of fine particulate matter and particle number concentration in households using biomass cookstoves in rural Honduras. *Environmental Pollution*, *258*, 113697. https://doi.org/10.1016/j.envpol.2019.113697

7. Williamson, C. J., Kupc, A., Axisa, D., **Bilsback, K. R**., Bui, T., Campuzano-Jost, P., Dollner, M., Froyd, K. D., Hodshire, A. L., Jimenez, J. L., Kodros, J. K., Luo, G., Murphy, D. M., Nault, B. A., Ray, E. A., Weinzierl, B. B., Wilson, J. C., Yu, F., Yu, P., Pierce, J. R., & Brock, C. A. (2019). A large source of cloud condensation nuclei from new particle formation in the tropics. *Nature*, *574*(7778), 399-403. https://doi.org/10.1038/s41586-019-1638-9

6. **Bilsback, K. R.,** Dahlke, J., Fedak, K. M., Good, N., Hecobian, A., Herckes, P., L'Orange, C., Mehaffy, J., Sullivan, A., Tryner, J., Van Zyl, L., Walker, E. S., Zhou, Y., Pierce, J. R., Wilson, A., Peel, J. L., & Volckens, J. (2019). A laboratory assessment of 120 air pollutant emissions from biomass and fossil fuel cookstoves. *Environmental science & technology*, *53*(12), 7114-7125. https://doi.org/10.1021/acs.est.8b07019

5. van Zyl, L., Tryner, J., **Bilsback, K. R.**, Good, N., Hecobian, A., Sullivan, A., Zhou, Y., Peel, J. L., & Volckens, J. (2019). Effects of fuel moisture content on emissions from a rocket-elbow cookstove. *Environmental science & technology*, *53*(8), 4648-4656. https://doi.org/10.1021/acs.est.9b00235

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2. Eilenberg, S. R., **Bilsback, K. R.**, Johnson, M., Kodros, J. K., Lipsky, E. M., Naluwagga, A., Fedak, K. M., Benka-Coker, M., Reynolds, B., Peel, J., Clark, M., Shan, M., Sambandam, S., L'Orange, C., Pierce, J. R., Subramanian, R., Volckens, J., & Robinson, A. L. (2018). Field measurements of solid-fuel cookstove emissions from uncontrolled cooking in China, Honduras, Uganda, and India. *Atmospheric Environment*, *190*, 116-125. https://doi.org/10.1016/j.atmosenv.2018.06.041

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*Full publication list with full-text download options here

Technical Reports & Expert Testimony

Bilsback, K. R. (2021). Public Health Testimony and Rebuttal Testimony on Consumers Energy's Integrated Resource Plan. View.

Bilsback, K. R., Krieger, E., Lukanov, B., Shetty, K., & Smith, A., (2022). Incorporating Health and Equity Metrics into the Minnesota Power 2021 Integrated Resource Plan. *PSE Healthy Energy*. View.

Selected Recent Presentations

Near-Source Health Risks of Non-Methane Volatile Organic Compounds from Natural Gas Super Emitters. *American Geophysical Union*. Poster presentation. Dec 12-16, 2023

Study: What does Minnesota Power's long-range plan mean for equity and public health? Webinar. May 19, 2022. View.

A Process-Level 3D Atmospheric Model for Secondary Organic Aerosol: Model Development and Applications to the GoAmazon Field Campaign. *American Geophysical Union*. Poster presentation. Dec 13-17, 2021

Vapors are Lost to the Walls, Not the Particles on the Wall: Development of Artifact-Corrected Parameters and Implications for Global Secondary Organic Aerosol. *American Geophysical Union*. Oral presentation. Dec 13-17, 2021

A Computationally Efficient Process-Level Model for Secondary Organic Aerosol: Model Development and Applications to Laboratory and Field Experiments Poster presentation. *Atmospheric Radiation Measurement/Atmospheric System Research Meeting*. Virtual. June 21-24, 2021

Cookstove Emissions, Climate, & Health Impacts: Integrated Lab, Field, & Modeling Study. Webinar presentation for Advancing Sustainable Household Energy Solutions. Jan 14, 2021. View

Estimated aerosol radiative and health effects of the residential coal ban in the Beijing-Tianjin-Hebei region of China. Oral presentation. *American Geophysical Union*. San Francisco, CA. Dec 9-13, 2019

Coupling laboratory and field measurements to estimate air pollutant emissions from cookstoves. Platform presentation. *American Association for Aerosol Research*. Portland, OR. Oct 14-18, 2019

Harmonizing atmospheric models and measurements from the laboratory and the field: An example using solid-fuel use. Oral presentation. *Frontiers of Atmospheric Science and Chemistry: Integration of Novel Applications and Technological Endeavors*. Boulder, CO. Sept 9-11, 2019

Communications

Bilsback, K. R. & Krieger, E. (2022). Four Ways to Bring Health and Equity to Utility Planning. *PSE Blog*. View.

Bilsback, K. R. (2020). Where there's coal there's air pollution: Measurements of residential coal heating stoves in China. *CSU School of Global Environmental Sustainability Blog*. View.

Bilsback, K. R. (2020). Clean cookstoves and the developing world. *Shared Air Podcast Guest*. Listen.

Fellowships And Leadership Experience

Environmental Health Scholar, Hearst Foundations and The Conversation US **2020-2021**

President, CSU Chapter of the American Association of Aerosol Research **2018-2021**

Sustainability Fellow, School of Global Environmental Sustainability **2019-2020**

Organizer, State of the Science: Looking to 2030 and Beyond **2020**

Mentor, Promoting Geoscience Research Education & Success **2019-2020**

15th Atmospheric Chemistry Colloquium for Emerging Senior Scientists **2019**

Publication & Proposal Reviewer, NASA Atmospheric Composition Campaign Data Analysis and Modeling (ACCDAM); ACS Earth and Space Chemistry; Development Engineering; Atmospheric Chemistry & Physics; Environmental Pollution; Journal of Geophysical Research: Atmospheres; Environmental Science & Technology; Atmospheric Environment; Atmosphere; and National Science Centre in Poland

Selected Teaching Experience

Graduate Teaching Fellowship, Introduction to Mechanical Engineering **2017-2018**

Graduate Teaching Assistant, Mechanics & Thermodynamics of Flow Processes **2017**

PCA Portfolio (#2)

Data Sources: Emissions data are from Witness Marietta's Workpapers (BJM-1); Generation data are from Witness Manning's Workpapers

Carbon Dioxide (CO2) Emissions (tons)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Belle River 1	3,639,474	3,636,988	1,855,811	508,833	481,228	354,444	514,977	536,072	481,027	405,855	323,231	310,450	292,187	231,261	228,176	182,545	133,280			
Belle River 2	2,828,589	3,681,008	3,346,786	1,816,321	340,047	277,154	382,800	400,617	338,963	262,737	229,779	213,270	171,301	216,180	120,683	118,228	92,584			
Belle River 1 & 2 (total)	**6,468,063**	tons	**lle River 1 & 2 Generation**	**6,069**	GWh															
Belle River 1 & 2 (rates)	**1,066**	tons per GWh																		
Monroe 1	2,886,159	4,492,767	3,649,685	4,303,952	3,153,858	4,274,568	4,300,835	4,435,047	3,298,194	4,306,170	4,289,416	4,220,191	1,236,102							
Monroe 2	4,101,079	4,101,817	3,593,082	3,155,053	4,101,617	4,101,416	4,101,482	3,265,047	4,102,153	4,101,193	4,101,147	3,768,083	1,505,927							
Monroe 3	4,517,877	3,225,425	4,290,535	4,306,284	4,321,820	1,933,550														
Monroe 4	4,575,709	4,460,497	3,254,429	4,398,091	4,282,558	1,969,665														
Monroe 1 & 2 (total)	**6,987,238**	tons	**Monroe 1 & 2 Generation**	**6,646**	GWh		**8,402,317**	**7,700,094**	**7,400,347**	**8,407,363**	**8,390,563**	**7,988,274**	**2,742,029**							
Monroe 3 & 4 (total)	**9,093,586**	tons	**Monroe 3 & 4 Generation**	**8,713**	GWh															
Total Monroe (total)	**16,080,824**	tons																		
Monroe 1 & 2 (rates)	**1051**	tons per GWh																		
Monroe 1 & 2 (rates)	**1044**	tons per GWh																		

Nitrogen Oxides (NOx) Emissions (tons)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Belle River 1	3,469	3,467	1,731	431	408	300	436	454	408	344	274	263	248	196	193	155	113			
Belle River 2	2,696	3,509	3,190	1,694	288	235	324	340	287	223	195	181	145	183	102	100	78			
Belle River 1 & 2	**6,165**	**6,976**	**4,921**	**2125**	**696**	**535**	**760**	**794**	**695**	**567**	**469**	**444**	**393**	**379**	**295**	**255**	**191**			
Belle River 1 & 2 (total)	**6,165**	tons																		
Belle River 1 & 2 (rates)	**1.02**	tons per GWh																		
Monroe 1	812	1,264	1,027	1,211	887	1,202	1,210	1,247	928	1,211	1,207	1,187	348							
Monroe 2	1,154	1,154	1,011	887	1,154	1,154	1,154	918	1,154	1,154	1,154	1,060	424							
Monroe 3	1,270	907	1,206	1,211	1,215	544														
Monroe 4	1,286	1,254	915	1,236	1,204	554														
Monroe 1 & 2	**1,966**	**2,418**	**2,038**	**2,098**	**2,041**	**2,356**	**2,364**	**2,165**	**2,082**	**2,365**	**2,361**	**2,247**	**772**							
Monroe 3 & 4	**2,556**	**2,161**	**2,121**	**2,447**	**2,419**	**1,098**														
Monroe 1 & 2 (total)	**1,966**	tons																		
Monroe 3 & 4 (total)	**2,556**	tons																		
Total Monroe (total)	**4,522**	tons																		
Monroe 1 & 2 (rates)	**0.30**	tons per GWh																		
Monroe 1 & 2 (rates)	**0.29**	tons per GWh																		

Sulfur Dioxide (SO2) Emissions (tons)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Belle River 1	10,232	10,225	4,199	3.4	3.3	2.4	3.5	3.6	3.3	2.8	2.2	2.1	2	1.6	1.5	1.2	0.9			
Belle River 2	7,952	10,349	9,409	4,120	2.3	1.9	2.6	2.7	2.3	1.8	1.6	1.4	1.2	1.5	0.8	0.8	0.6			
Belle River 1 & 2	**18,184**	**20,574**	**13,608**	**4,123**	**6**	**4**	**6**	**6**	**6**	**5**	**4**	**4**	**3**	**3**	**2**	**2**	**2**			
Belle River 1 & 2 (total)	**18,184**	tons																		
Belle River 1 & 2 (rates)	**3.0**	tons per GWh																		
Monroe 1	538	591	481	568	403	546	550	567	422	550	548	539	158							
Monroe 2	542	538	473	627	786	786	786	626	787	786	786	722	288							
Monroe 3	621	423	518	523	506	226														
Monroe 4	643	585	496	533	501	231														
Monroe 1 & 2	**1,080**	**1,129**	**954**	**1,195**	**1,189**	**1,332**	**1336**	**1193**	**1209**	**1336**	**1334**	**1261**	**446**							
Monroe 3 & 4	**1,264**	**1,008**	**1,014**	**1,056**	**1,007**	**457**														
Monroe 1 & 2 (total)	**1,080**	tons																		
Monroe 3 & 4 (total)	**1,264**	tons																		
Total Monroe (total)	**2,344**	tons																		
Monroe 1 & 2 (rates)	**0.16**	tons per GWh																		
Monroe 1 & 2 (rates)	**0.15**	tons per GWh																		

Particulate Matter (PM) Emissions (tons)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Belle River 1	17	17	28	30	29	21	31	32	29	24	19	18	17	14	14	11	8			
Belle River 2	16	21	19	29	20	16	23	24	20	16	14	13	10	13	7	7	5			
Belle River 1 & 2	**33**	**38**	**47**	**59**	**49**	**37**	**54**	**56**	**49**	**40**	**33**	**31**	**27**	**27**	**21**	**18**	**13**			
Belle River 1 & 2 (total)	**33**	tons																		
Belle River 1 & 2 (rates)	**0.005**	tons per GWh																		
Monroe 1	60	93	76	89	65	89	89	92	68	89	89	87	26							
Monroe 2	104	104	91	80	104	104	104	83	104	104	104	95	38							
Monroe 3	79	57	75	75	76	34														
Monroe 4	76	74	54	73	71	33														
Monroe 1 & 2	**164**	**197**	**167**	**169**	**169**	**193**	**193**	**175**	**172**	**193**	**193**	**182**	**64**							
Monroe 3 & 4	**155**	**131**	**129**	**148**	**147**	**67**														
Monroe 1 & 2 (total)	**164**	tons																		
Monroe 3 & 4 (total)	**155**	tons																		
Total Monroe (total)	**319**	tons																		
Monroe 1 & 2 (rates)	**0.025**	tons per GWh																		
Monroe 1 & 2 (rates)	**0.018**	tons per GWh																		

Volatile Organic Carbon (VOC) Emissions (tons)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Belle River 1	57	57	39	22	20	15	22	23	20	17	14	13	12	10	10	8	6			

Belle River 2	44	58	53	38	14	12	16	17	14	11	10	9	7	9	5	5	4
Belle River 1 & 2	**101**	**115**	**92**	**60**	**34**	**27**	**38**	**40**	**34**	**28**	**24**	**22**	**19**	**19**	**15**	**13**	**10**
Belle River 1 & 2 (total)	**101**	tons															
Belle River 1 & 2 (rates)	**0.017**	tons per GWh															
Monroe 1	7	11	9	10	8	10	10	11	8	10	10	10	3				
Monroe 2	10	10	9	8	10	10	10	8	10	10	10	9	4				
Monroe 3	11	8	10	10	10	5											
Monroe 4	11	11	8	10	10	5											
Monroe 1 & 2	**17**	**21**	**18**	**18**	**18**	**20**	**20**	**19**	**18**	**20**	**20**	**19**	**7**				
Monroe 3 & 4	**22**	**19**	**18**	**20**	**20**	**10**											
Monroe 1 & 2 (total)	**17**	tons															
Monroe 3 & 4 (total)	**22**	tons															
Total Monroe (total)	**39**	tons															
Monroe 1 & 2 (rates)	**0.003**	tons per GWh															
Monroe 1 & 2 (rates)	**0.003**	tons per GWh															

Data Source: https://www.eia.gov/electricity/data/eia860/ (2020)

Stack parameters	height (ft)	**height (m)**	area at top (ft2)	**diam (m)**	temp high (F)	**temp high (K)**	velocity high (ft/s)	**velocity high (m/s)**
Belle River 1	665	**203**	510	**8**	330	**439**	90	**27**
Belle River 2	665	**203**	510	**8**	290	**416**	90	**27**
Monroe 1	805	**245**	616	**9**	270.0	**405**	142	**43**
Monroe 2	805	**245**	616	**9**	270	**405**	142	**43**
Monroe 3	805	**245**	616	**9**	127	**326**	142	**43**
Monroe 4	805	**245**	616	**9**	127	**326**	142	**43**
Greenwood CTG121	496	**151**						

Data Source:

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Year	Operating Tim	Sum of the Operating Tim	Gross Load (MWh	Steam Load (1000 lb	SO2 Mass (short tons	SO2 Rate (lbs/mmBtu	CO2 Mass (short tons	CO2 Rate (short tons/mmBtu	NOx Mass (short tons	NOx Rate (lbs/mmBtu	Heat Input (m	Primary Fuel Type	Secondary Fu	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
MI	Monroe	1733	1		2018	6537	6527.03	3792857.21		1070.939	0.0558	3860239.61	0.105	1319.23	0.0754	36806235.7	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	1		2019	8104	8096.89	4682829.19		1137.976	0.0515	4655751.01	0.105	1387.909	0.0641	44391227.8	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	1		2020	6584	6573.09	3492574.9		1055.51	0.061	3509057.42	0.105	1042.722	0.0693	33457821.6	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	1		2021	6868	6861.77	3824683.65		946.604	0.0488	3823522.82	0.105	1072.992	0.0631	36456193.6	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Monroe	1733	1		2022	7871	7858.55	4928345.16		1100.769	0.0466	4995615.17	0.105	1307.331	0.0571	47631725.1	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Monroe	1733	2		2018	7747	7734.73	4570613.27		1055.859	0.0452	4778440.76	0.105	1460.379	0.0668	45561052.6	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	2		2019	8051	8038	4395767.92		1141.236	0.0522	4456339.33	0.105	1289.081	0.0618	42489942.2	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	2		2020	5538	5523.71	2901451.99		977.789	0.0664	3000183.17	0.105	801.237	0.0594	28605884.5	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	2		2021	7719	7706.16	4440879.89		1115.047	0.0511	4427939.97	0.105	1140.196	0.056	42219106	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Monroe	1733	2		2022	5387	5374.54	3234089.38		793.391	0.054	3137169.34	0.105	984.625	0.0717	29911967.3	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Monroe	1733	3		2018	7957	7952.05	4797201.21		808.33	0.0349	4652409.54	0.105	1433.998	0.0658	44335238.7	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	3		2019	5266	5260.16	3270561.9		787.71	0.049	3276526.28	0.105	1024.036	0.0678	31223756.8	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	3		2020	6899	6884.11	3963451.08		819.6	0.0435	3837860.92	0.105	1091.148	0.0634	36573012.8	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	3		2021	7831	7823.3	4908091.66		848.532	0.0367	4749613.45	0.105	1456.123	0.066	45261585.4	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Monroe	1733	3		2022	7116	7087.06	4176623.02		800.43	0.0426	4146531.77	0.105	1293.321	0.0711	39514477.1	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Monroe	1733	4		2018	7264	7253.79	4607638.7		919.249	0.04	4642332.75	0.105	1513.347	0.0713	44239250	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	4		2019	7221	7209.84	4233869.37		892.913	0.044	4170739.88	0.105	1290.818	0.0675	39745154.9	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	4		2020	6901	6889.02	3936377.84		929.657	0.0482	3929607.1	0.105	1280.275	0.0706	37447283.4	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Monroe	1733	4		2021	4776	4758.72	2742143.32		782.968	0.0562	2720829.5	0.105	874.35	0.0755	25928217.1	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Monroe	1733	4		2022	6708	6699.55	4248427.3		888.158	0.0457	4010699.77	0.105	1314.35	0.0713	38220063.8	Coal	Diesel Oil	Cell burner boiler	Wet Limestone	Low NOx Cell Burner,Selective Catalytic Reduct	Electrostatic Precipitator		ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Belle River	6034	1		2018	6828	6814.28	3847277.17		11384.784	0.6238	3961122.15	0.1049	3857.1	0.2007	37768164.3	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Belle River	6034	1		2019	3477	3467	1631173.26		4739.351	0.5644	1698330.82	0.1048	1480.958	0.1768	16193080.1	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Belle River	6034	1		2020	6547	6543.18	2734737.82		8704.394	0.6359	2829488.4	0.105	2835.029	0.212	26978351.9	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Belle River	6034	1		2021	7152	7139.89	3566293.54		10377.338	0.5853	3658461.21	0.105	3516.849	0.2003	34882356.6	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Belle River	6034	1		2022	5766	5745.69	3057612.67		8212.738	0.6361	3011256.3	0.1046	2940.672	0.2002	28711481.4	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Belle River	6034	2		2018	7422	7407.6	4241687.55		12637.73	0.5854	4413910.44	0.105	4395.036	0.2038	42085336.9	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Belle River	6034	2		2019	7884	7876.48	4235167.37		12753.445	0.6063	4366159.31	0.105	3988.847	0.1915	41630069.1	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Belle River	6034	2		2020	3833	3816.37	1838024.76		5892.147	1.3551	1928299.33	0.0986	1911.493	0.1904	18386015	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG2, CSSO2G1, MATS
MI	Belle River	6034	2		2021	7571	7557.46	4028701.8		11973.833	0.5823	4247466.61	0.105	4459.964	0.2166	40498336.9	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG3, CSSO2G1, MATS
MI	Belle River	6034	2		2022	7781	7766.84	4169943.76		12375.946	0.5846	4366489.65	0.1049	4313.716	0.203	41633171.4	Coal	Diesel Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitatc	Halogenated PAC Sorbent Injecti	ARP, CSNOX, CSOSG3, CSSO2G1, MATS

	Monroe, Units 1 &2, Coal					
Monroe 1 & 2 Units	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Monroe 3 & 4 Units	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
COBRA Emissions Year	2023	2023	2023	2028	2028	2028
DTE Emissions Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
$ Total Health Impacts (low estimate)	$143,853,430	$162,878,859	$137,698,857	$165,201,978	$163,845,110	$185,744,749
$ Total Health Impacts (high estimate)	$324,497,332	$367,409,087	$310,615,167	$372,350,847	$369,292,822	$418,647,245
Mortality(low estimate)	13	15	12	14	14	16
$ Mortality(low estimate)	$141,539,973	$160,259,332	$135,484,290	$162,749,526	$161,412,769	$182,987,289
Mortality(high estimate)	29	33	28	33	32	37
$ Mortality(high estimate)	$320,605,597	$363,006,128	$306,892,925	$368,130,633	$365,107,508	$413,903,047
Infant Mortality	0	0	0	0	0	0
$ Infant Mortality	$862,660	$978,382	$827,181	$880,356	$873,265	$990,196
Nonfatal Heart Attacks(low estimate)	1	1	1	1	1	2
$ Nonfatal Heart Attacks(low estimate)	$190,388	$215,145	$181,870	$213,248	$211,464	$239,672
Nonfatal Heart Attacks(high estimate)	11	12	11	13	13	14
$ Nonfatal Heart Attacks(high estimate)	$1,768,665	$1,998,576	$1,689,545	$1,981,010	$1,964,438	$2,226,411
Hospital Admits, All Respiratory	3	3	3	3	3	4
Hospital Admits All Respiratory Direct	2	2	2	2	2	3
Hospital Admits, Asthma	0	0	0	0	0	0
Hospital Admits, Chronic Lung Disease	1	1	1	1	1	1
$ Hospital Admits, All Respiratory	$99,635	$112,617	$95,200	$114,158	$113,205	$128,309
Hospital Admits, Cardiovascular(except heart attacks)	3	3	3	3	3	4
$ Hospital Admits, Cardiovascular (except heart attack	$142,054	$160,608	$135,770	$161,127	$159,786	$181,113
Acute Bronchitis	15	17	14	17	17	19
$ Acute Bronchitis	$9,282	$10,509	$8,885	$10,511	$10,424	$11,817
Upper Respiratory Symptoms	272	308	261	306	303	344
$ Upper Respiratory Symptoms	$11,633	$13,172	$11,135	$13,215	$13,106	$14,858
Lower Respiratory Symptoms	191	217	183	214	213	241
$ Lower Respiratory Symptoms	$5,166	$5,850	$4,945	$5,857	$5,809	$6,586
Emergency Room Visits, Asthma	6	7	6	7	7	7
$ Emergency Room Visits, Asthma	$3,444	$3,897	$3,294	$3,718	$3,687	$4,179
Minor Restricted Activity Days	7,975	9,025	7,629	8,376	8,307	9,416
$ Minor Restricted Activity Days	$699,169	$791,154	$668,834	$743,117	$736,982	$835,425
Work Loss Days	1,344	1,521	1,286	1,418	1,407	1,595
$ Work Loss Days	$269,073	$304,473	$257,397	$283,931	$281,587	$319,201
Asthma Exacerbation	282	320	270	309	307	348
Asthma Exacerbation, Cough	64	73	61	70	70	79
Asthma Exacerbation, Shortness of Breath	86	98	83	95	94	106
Asthma Exacerbation, Wheeze	132	149	126	144	143	162
$ Asthma Exacerbation	$20,953	$23,722	$20,054	$23,215	$23,025	$26,102

Monroe 1 & 2 Units	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Monroe 3 & 4 Units	**No**	**No**	**No**	**No**	**No**	**No**
COBRA Emissions Year	2028	2028	2028	2028	2028	2028
DTE Emissions Year	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
$ Total Health Impacts (low estimate)	$186,152,579	$167,886,296	$166,754,415	$186,169,136	$185,965,221	$175,916,984
$ Total Health Impacts (high estimate)	$419,566,371	$378,400,286	$375,849,504	$419,603,687	$419,144,124	$396,498,928
Mortality(low estimate)	16.3	14.7	14.6	16.3	16.3	15.4
$ Mortality(low estimate)	$183,389,071	$165,393,961	$164,278,886	$183,405,384	$183,204,493	$173,305,440
Mortality(high estimate)	36.8	33.2	33.0	36.8	36.8	34.8
$ Mortality(high estimate)	$414,811,658	$374,112,424	$371,589,891	$414,848,548	$414,394,243	$392,005,568
Infant Mortality	0	0	0	0	0	0
$ Infant Mortality	$992,321	$895,092	$888,774	$992,407	$991,345	$937,719
Nonfatal Heart Attacks(low estimate)	2	1	1	2	2	1
$ Nonfatal Heart Attacks(low estimate)	$240,211	$216,599	$215,218	$240,233	$239,964	$227,011
Nonfatal Heart Attacks(high estimate)	14	13	13	14	14	13
$ Nonfatal Heart Attacks(high estimate)	$2,231,417	$2,012,126	$1,999,301	$2,231,619	$2,229,115	$2,108,828
Hospital Admits, All Respiratory	4	3	3	4	4	3
Hospital Admits All Respiratory Direct	3	2	2	3	3	2
Hospital Admits, Asthma	0	0	0	0	0	0
Hospital Admits, Chronic Lung Disease	1	1	1	1	1	1
$ Hospital Admits, All Respiratory	$128,597	$115,958	$115,215	$128,609	$128,465	$121,530
Hospital Admits, Cardiovascular(except heart attacks)	4	3	3	4	4	3
$ Hospital Admits, Cardiovascular (except heart attack	$181,517	$163,682	$162,623	$181,534	$181,331	$171,540
Acute Bronchitis	19	17	17	19	19	18
$ Acute Bronchitis	$11,843	$10,681	$10,609	$11,844	$11,831	$11,192
Upper Respiratory Symptoms	344	311	308	344	344	325
$ Upper Respiratory Symptoms	$14,891	$13,430	$13,339	$14,892	$14,876	$14,072
Lower Respiratory Symptoms	241	218	216	242	241	228
$ Lower Respiratory Symptoms	$6,600	$5,952	$5,912	$6,601	$6,593	$6,237
Emergency Room Visits, Asthma	7	7	7	7	7	7
$ Emergency Room Visits, Asthma	$4,189	$3,777	$3,752	$4,189	$4,184	$3,958
Minor Restricted Activity Days	9,437	8,510	8,454	9,438	9,427	8,918
$ Minor Restricted Activity Days	$837,272	$755,072	$750,067	$837,347	$836,423	$791,243
Work Loss Days	1,598	1,441	1,432	1,598	1,596	1,510
$ Work Loss Days	$319,907	$288,499	$286,586	$319,936	$319,583	$302,320
Asthma Exacerbation	348	314	312	348	348	329
Asthma Exacerbation, Cough	79	71	71	79	79	75
Asthma Exacerbation, Shortness of Breath	107	96	95	107	106	101
Asthma Exacerbation, Wheeze	163	147	146	163	163	154
$ Asthma Exacerbation	$26,160	$23,592	$23,434	$26,162	$26,133	$24,721

Monroe 1 & 2 Units	**Yes**	**Cummulative Impacts of Units 1 & 2 2023-2035**	**Cummulative Impacts of Units 1 & 2 2031-2035**
Monroe 3 & 4 Units	**No**		
COBRA Emissions Year	2028		
DTE Emissions Year	**2035**		
$ Total Health Impacts (low estimate)	$61,742,393	$2,089,810,007	$776,548,150
$ Total Health Impacts (high estimate)	$139,170,397	$4,711,045,797	$1,750,266,640
Mortality(low estimate)	5.4	184	68
$ Mortality(low estimate)	$60,825,811	$2,058,236,223	$765,020,013
Mortality(high estimate)	12.2	416	154
$ Mortality(high estimate)	$137,593,234	$4,657,001,405	$1,730,431,484
Infant Mortality	0	1	0
$ Infant Mortality	$329,113	$11,438,811	$4,139,359
Nonfatal Heart Attacks(low estimate)	1	17	6
$ Nonfatal Heart Attacks(low estimate)	$79,673	$2,710,697	$1,002,099
Nonfatal Heart Attacks(high estimate)	5	160	59
$ Nonfatal Heart Attacks(high estimate)	$740,255	$25,181,306	$9,309,117
Hospital Admits, All Respiratory	1	40	15
Hospital Admits All Respiratory Direct	1	29	11
Hospital Admits, Asthma	0	4	1
Hospital Admits, Chronic Lung Disease	0	7	3
$ Hospital Admits, All Respiratory	$42,653	$1,444,149	$536,470
Hospital Admits, Cardiovascular(except heart attacks)	1	41	15
$ Hospital Admits, Cardiovascular (except heart attack	$60,204	$2,042,889	$757,232
Acute Bronchitis	6	214	79
$ Acute Bronchitis	$3,929	$133,359	$49,406
Upper Respiratory Symptoms	114	3,885	1,437
$ Upper Respiratory Symptoms	$4,939	$167,558	$62,118
Lower Respiratory Symptoms	80	2,725	1,007
$ Lower Respiratory Symptoms	$2,189	$74,299	$27,533
Emergency Room Visits, Asthma	2	85	31
$ Emergency Room Visits, Asthma	$1,389	$47,659	$17,474
Minor Restricted Activity Days	3,130	108,042	39,367
$ Minor Restricted Activity Days	$277,711	$9,559,815	$3,492,790
Work Loss Days	530	18,276	6,666
$ Work Loss Days	$106,106	$3,658,598	$1,334,530
Asthma Exacerbation	116	3,951	1,453
Asthma Exacerbation, Cough	26	897	330
Asthma Exacerbation, Shortness of Breath	35	1,208	444
Asthma Exacerbation, Wheeze	54	1,846	679
$ Asthma Exacerbation	$8,676	$295,949	$109,126

	Monroe, Units 3 & 4, Coal					
Monroe 1 & 2 Units	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Monroe 3 & 4 Units	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
COBRA Emissions Year	2023	2023	2023	2028	2028	2028
DTE Emissions Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
$ Total Health Impacts (low estimate)	$162,374,905	$133,383,007	$132,606,337	$155,447,530	$151,326,029	$68,768,253
$ Total Health Impacts (high estimate)	$366,273,602	$300,881,024	$299,129,200	$350,367,518	$341,078,620	$155,006,420
Mortality(low estimate)	15	11.99	11.92	13.59	13.23	6.01
$ Mortality(low estimate)	$159,764,049	$131,238,292	$130,474,119	$153,140,184	$149,079,833	$67,747,502
Mortality(high estimate)	33	27.17	27.01	30.73	29.92	13.60
$ Mortality(high estimate)	$361,874,041	$297,268,060	$295,536,876	$346,395,016	$337,212,281	$153,249,385
Infant Mortality	0.08	0.07	0.06	0.07	0.06	0.03
$ Infant Mortality	$970,168	$797,471	$792,642	$827,409	$805,863	$366,236
Nonfatal Heart Attacks(low estimate)	1.34	1.10	1.10	1.28	1.24	0.57
$ Nonfatal Heart Attacks(low estimate)	$215,776	$177,110	$176,127	$200,867	$195,436	$88,805
Nonfatal Heart Attacks(high estimate)	12.46	10.23	10.17	11.88	11.56	5.25
$ Nonfatal Heart Attacks(high estimate)	$2,004,480	$1,645,358	$1,636,233	$1,866,023	$1,815,579	$825,088
Hospital Admits, All Respiratory	3.09	2.54	2.52	2.99	2.91	1.32
Hospital Admits All Respiratory Direct	2.16	1.77	1.76	2.18	2.12	0.96
Hospital Admits, Asthma	0.30	0.24	0.24	0.27	0.26	0.12
Hospital Admits, Chronic Lung Disease	0.63	0.52	0.52	0.54	0.53	0.24
$ Hospital Admits, All Respiratory	$112,864	$92,647	$92,130	$107,514	$104,613	$47,536
Hospital Admits, Cardiovascular(except heart attacks)	3.15	2.58	2.57	3.02	2.94	1.34
$ Hospital Admits, Cardiovascular (except heart attack	$160,816	$132,025	$131,283	$151,718	$147,638	$67,086
Acute Bronchitis	16.98	13.95	13.86	15.83	15.41	7.01
$ Acute Bronchitis	$10,476	$8,606	$8,556	$9,889	$9,627	$4,375
Upper Respiratory Symptoms	307.30	252.43	250.96	287.52	279.91	127.20
$ Upper Respiratory Symptoms	$13,129	$10,785	$10,722	$12,433	$12,103	$5,500
Lower Respiratory Symptoms	215.92	177.37	176.34	201.63	196.28	89.21
$ Lower Respiratory Symptoms	$5,831	$4,790	$4,762	$5,511	$5,365	$2,438
Emergency Room Visits, Asthma	6.91	5.67	5.64	6.21	6.05	2.75
$ Emergency Room Visits, Asthma	$3,893	$3,197	$3,179	$3,499	$3,406	$1,548
Minor Restricted Activity Days	9,013.35	7,402.26	7,359.79	7,883.21	7,672.97	3,486.84
$ Minor Restricted Activity Days	$790,154	$648,918	$645,195	$699,426	$680,772	$309,364
Work Loss Days	1,519.05	1,247.51	1,240.36	1,334.94	1,299.33	590.45
$ Work Loss Days	$304,094	$249,736	$248,304	$267,238	$260,110	$118,200
Asthma Exacerbation	318.76	261.83	260.31	290.83	283.12	128.66
Asthma Exacerbation, Cough	72.38	59.45	59.11	66.04	64.29	29.21
Asthma Exacerbation, Shortness of Breath	97.47	80.06	79.60	88.93	86.57	39.34
Asthma Exacerbation, Wheeze	148.92	122.32	121.61	135.87	132.26	60.10
$ Asthma Exacerbation	$23,655	$19,430	$19,317	$21,843	$21,263	$9,663

Monroe 1 & 2 Units Monroe 3 & 4 Units COBRA Emissions Year DTE Emissions Year	Cummulative Impacts of Units 1 & 2 2023-2028
$ Total Health Impacts (low estimate)	$803,906,061
$ Total Health Impacts (high estimate)	$1,812,736,384
Mortality(low estimate)	71
$ Mortality(low estimate)	$791,443,979
Mortality(high estimate)	162
$ Mortality(high estimate)	$1,791,535,660
Infant Mortality	0
$ Infant Mortality	$4,559,789
Nonfatal Heart Attacks(low estimate)	7
$ Nonfatal Heart Attacks(low estimate)	$1,054,120
Nonfatal Heart Attacks(high estimate)	62
$ Nonfatal Heart Attacks(high estimate)	$9,792,761
Hospital Admits, All Respiratory	15
Hospital Admits All Respiratory Direct	11
Hospital Admits, Asthma	1
Hospital Admits, Chronic Lung Disease	3
$ Hospital Admits, All Respiratory	$557,304
Hospital Admits, Cardiovascular(except heart attacks)	16
$ Hospital Admits, Cardiovascular (except heart attack	$790,567
Acute Bronchitis	83
$ Acute Bronchitis	$51,529
Upper Respiratory Symptoms	1,505
$ Upper Respiratory Symptoms	$64,672
Lower Respiratory Symptoms	1,057
$ Lower Respiratory Symptoms	$28,697
Emergency Room Visits, Asthma	33
$ Emergency Room Visits, Asthma	$18,722
Minor Restricted Activity Days	42,818
$ Minor Restricted Activity Days	$3,773,830
Work Loss Days	7,232
$ Work Loss Days	$1,447,682
Asthma Exacerbation	1,544
Asthma Exacerbation, Cough	350
Asthma Exacerbation, Shortness of Breath	472
Asthma Exacerbation, Wheeze	721
$ Asthma Exacerbation	$115,171

	Belle River, Units 1 &2, Coal					
Fuel	Coal	Coal	Coal	Coal	Gas	Gas
COBRA Emissions Year	2023	2023	2023	2028	2028	2028
DTE Emissions Year	2023	2024	2025	2026	2027	2028
$ Total Health Impacts (low estimate)	$795,795,420	$900,438,139	$601,478,383	$212,427,376	$14,533,858	$11,048,167
$ Total Health Impacts (high estimate)	$1,794,657,493	$2,030,507,519	$1,356,607,263	$478,892,605	$32,776,339	$24,915,602
Mortality(low estimate)	72	81.01	54.11	18.58	1.3	0.97
$ Mortality(low estimate)	$783,437,860	$886,455,459	$592,141,191	$209,401,853	$14,333,021	$10,895,475
Mortality(high estimate)	162	183.23	122.42	41.99	2.9	2.19
$ Mortality(high estimate)	$1,772,198,003	$2,005,097,137	$1,339,632,467	$473,270,010	$32,399,762	$24,629,310
Infant Mortality	0.33	0.37	0.25	0.08	0.00	0.00
$ Infant Mortality	$3,999,197	$4,525,169	$3,021,664	$944,027	$62,619	$47,609
Nonfatal Heart Attacks(low estimate)	7.59	8.59	5.74	2.00	0.14	0.10
$ Nonfatal Heart Attacks(low estimate)	$1,220,585	$1,381,115	$922,419	$313,361	$21,196	$16,113
Nonfatal Heart Attacks(high estimate)	70.40	79.65	53.23	18.58	1.26	0.96
$ Nonfatal Heart Attacks(high estimate)	$11,322,515	$12,808,816	$8,560,022	$2,910,434	$196,936	$149,712
Hospital Admits, All Respiratory	17.22	19.48	13.01	4.60	0.31	0.24
Hospital Admits All Respiratory Direct	11.85	13.41	8.96	3.32	0.22	0.17
Hospital Admits, Asthma	1.41	1.60	1.07	0.35	0.02	0.02
Hospital Admits, Chronic Lung Disease	3.95	4.47	2.98	0.93	0.06	0.05
$ Hospital Admits, All Respiratory	$627,631	$710,184	$474,282	$165,295	$11,145	$8,472
Hospital Admits, Cardiovascular(except heart attacks)	17.21	19.48	13.01	4.57	0.31	0.23
$ Hospital Admits, Cardiovascular (except heart attacks)	$879,955	$995,700	$664,925	$229,364	$15,408	$11,714
Acute Bronchitis	79.57	90.02	60.13	20.58	1.36	1.03
$ Acute Bronchitis	$49,101	$55,550	$37,107	$12,855	$847	$644
Upper Respiratory Symptoms	1,441	1,630.98	1,088.93	373.57	25	18.72
$ Upper Respiratory Symptoms	$61,582	$69,682	$46,524	$16,153	$1,065	$809
Lower Respiratory Symptoms	1,012.21	1,145.21	764.89	262.06	17.27	13.13
$ Lower Respiratory Symptoms	$27,335	$30,927	$20,656	$7,162	$472	$359
Emergency Room Visits, Asthma	33.86	38.31	25.58	8.40	0.55	0.42
$ Emergency Room Visits, Asthma	$19,077	$21,586	$14,413	$4,731	$310	$236
Minor Restricted Activity Days	44,171.84	49,979.77	33,374.61	10,636.96	700.77	532.80
$ Minor Restricted Activity Days	$3,872,319	$4,381,470	$2,925,781	$943,748	$62,175	$47,272
Work Loss Days	7,437	8,414.67	5,618.59	1,800.07	119	90.13
$ Work Loss Days	$1,488,726	$1,684,508	$1,124,770	$360,351	$23,730	$18,042
Asthma Exacerbation	1,510	1,708.57	1,140.74	379.14	25	18.93
Asthma Exacerbation, Cough	342.85	387.95	259.02	86.09	5.65	4.30
Asthma Exacerbation, Shortness of Breath	461.69	522.41	348.80	115.93	7.61	5.79
Asthma Exacerbation, Wheeze	705.43	798.22	532.93	177.12	11.63	8.84
$ Asthma Exacerbation	$112,051	$126,790	$84,652	$28,475	$1,870	$1,422

Fuel	Gas	Gas	Gas	Gas	Gas	Gas	Gas
COBRA Emissions Year	2028	2028	2028	2028	2028	2028	2028
DTE Emissions Year	2029	2030	2031	2032	2033	2034	2035
$ Total Health Impacts (low estimate)	$15,917,961	$16,557,741	$14,523,608	$11,857,014	$9,789,192	$9,241,653	$8,092,304
$ Total Health Impacts (high estimate)	$35,897,702	$37,340,459	$32,753,229	$26,739,702	$22,076,455	$20,841,646	$18,249,662
Mortality(low estimate)	1.39	1.45	1.27	1.04	0.86	0.81	0.71
$ Mortality(low estimate)	$15,698,035	$16,328,959	$14,322,917	$11,693,169	$9,653,920	$9,113,930	$7,980,453
Mortality(high estimate)	3.15	3.27	2.87	2.35	1.94	1.83	1.60
$ Mortality(high estimate)	$35,485,313	$36,911,475	$32,376,922	$26,432,483	$21,822,811	$20,602,167	$18,039,951
Infant Mortality	0.01	0.01	0.00	0.00	0.00	0.00	0.00
$ Infant Mortality	$68,570	$71,332	$62,574	$51,085	$42,177	$39,823	$34,875
Nonfatal Heart Attacks(low estimate)	0.15	0.15	0.14	0.11	0.09	0.09	0.08
$ Nonfatal Heart Attacks(low estimate)	$23,213	$24,146	$21,181	$17,292	$14,276	$13,478	$11,802
Nonfatal Heart Attacks(high estimate)	1.38	1.43	1.26	1.03	0.85	0.80	0.70
$ Nonfatal Heart Attacks(high estimate)	$215,677	$224,349	$196,796	$160,665	$132,647	$125,234	$109,663
Hospital Admits, All Respiratory	0.34	0.35	0.31	0.25	0.21	0.20	0.17
Hospital Admits All Respiratory Direct	0.24	0.25	0.22	0.18	0.15	0.14	0.12
Hospital Admits, Asthma	0.03	0.03	0.02	0.02	0.02	0.01	0.01
Hospital Admits, Chronic Lung Disease	0.07	0.07	0.06	0.05	0.04	0.04	0.04
$ Hospital Admits, All Respiratory	$12,205	$12,696	$11,137	$9,092	$7,507	$7,087	$6,206
Hospital Admits, Cardiovascular(except heart attacks)	0.34	0.35	0.31	0.25	0.21	0.20	0.17
$ Hospital Admits, Cardiovascular (except heart attacks)	$16,874	$17,553	$15,397	$12,570	$10,378	$9,798	$8,580
Acute Bronchitis	1.49	1.55	1.36	1.11	0.91	0.86	0.76
$ Acute Bronchitis	$928	$965	$847	$691	$571	$539	$472
Upper Respiratory Symptoms	26.96	28.04	24.60	20.08	16.58	15.66	13.71
$ Upper Respiratory Symptoms	$1,166	$1,213	$1,064	$868	$717	$677	$593
Lower Respiratory Symptoms	18.91	19.67	17.26	14.09	11.63	10.98	9.62
$ Lower Respiratory Symptoms	$517	$538	$472	$385	$318	$300	$263
Emergency Room Visits, Asthma	0.60	0.63	0.55	0.45	0.37	0.35	0.31
$ Emergency Room Visits, Asthma	$340	$353	$310	$253	$209	$197	$173
Minor Restricted Activity Days	767.34	798.25	700.26	571.69	472.00	445.67	390.30
$ Minor Restricted Activity Days	$68,081	$70,824	$62,129	$50,723	$41,877	$39,542	$34,629
Work Loss Days	129.80	135.03	118.45	96.71	79.84	75.39	66.02
$ Work Loss Days	$25,985	$27,031	$23,713	$19,359	$15,983	$15,092	$13,217
Asthma Exacerbation	27.26	28.36	24.88	20.31	16.77	15.83	13.87
Asthma Exacerbation, Cough	6.19	6.44	5.65	4.61	3.81	3.60	3.15
Asthma Exacerbation, Shortness of Breath	8.34	8.67	7.61	6.21	5.13	4.84	4.24
Asthma Exacerbation, Wheeze	12.74	13.25	11.62	9.49	7.83	7.40	6.48
$ Asthma Exacerbation	$2,048	$2,130	$1,869	$1,525	$1,259	$1,189	$1,042

Fuel	Gas	Gas	Gas	Gas
COBRA Emissions Year	2028	2028	2028	2028
DTE Emissions Year	**2036**	**2037**	**2038**	**2039**
$ Total Health Impacts (low estimate)	$7,948,802	$6,170,008	$5,323,169	$3,939,134
$ Total Health Impacts (high estimate)	$17,926,108	$13,914,620	$12,004,823	$8,883,516
Mortality(low estimate)	0.70	0.54	0.47	0.34
$ Mortality(low estimate)	$7,838,984	$6,084,771	$5,249,617	$3,884,670
Mortality(high estimate)	1.57	1.22	1.05	0.78
$ Mortality(high estimate)	$17,720,179	$13,754,782	$11,866,905	$8,781,410
Infant Mortality	0.00	0.00	0.00	0.00
$ Infant Mortality	$34,240	$26,576	$22,933	$16,982
Nonfatal Heart Attacks(low estimate)	0.07	0.06	0.05	0.04
$ Nonfatal Heart Attacks(low estimate)	$11,591	$8,997	$7,763	$5,746
Nonfatal Heart Attacks(high estimate)	0.69	0.53	0.46	0.34
$ Nonfatal Heart Attacks(high estimate)	$107,703	$83,599	$72,130	$53,388
Hospital Admits, All Respiratory	0.17	0.13	0.11	0.08
Hospital Admits All Respiratory Direct	0.12	0.09	0.08	0.06
Hospital Admits, Asthma	0.01	0.01	0.01	0.01
Hospital Admits, Chronic Lung Disease	0.03	0.03	0.02	0.02
$ Hospital Admits, All Respiratory	$6,095	$4,731	$4,082	$3,021
Hospital Admits, Cardiovascular(except heart attacks)	0.17	0.13	0.11	0.08
$ Hospital Admits, Cardiovascular (except heart attacks)	$8,426	$6,540	$5,643	$4,178
Acute Bronchitis	0.74	0.58	0.50	0.37
$ Acute Bronchitis	$463	$360	$310	$230
Upper Respiratory Symptoms	13.46	10.45	9.02	6.68
$ Upper Respiratory Symptoms	$582	$452	$390	$289
Lower Respiratory Symptoms	9.44	7.33	6.33	4.68
$ Lower Respiratory Symptoms	$258	$200	$173	$128
Emergency Room Visits, Asthma	0.30	0.23	0.20	0.15
$ Emergency Room Visits, Asthma	$170	$132	$114	$84
Minor Restricted Activity Days	383.16	297.39	256.63	190.07
$ Minor Restricted Activity Days	$33,996	$26,386	$22,770	$16,863
Work Loss Days	64.81	50.31	43.41	32.15
$ Work Loss Days	$12,975	$10,071	$8,690	$6,436
Asthma Exacerbation	13.61	10.57	9.12	6.75
Asthma Exacerbation, Cough	3.09	2.40	2.07	1.53
Asthma Exacerbation, Shortness of Breath	4.16	3.23	2.79	2.06
Asthma Exacerbation, Wheeze	6.36	4.94	4.26	3.15
$ Asthma Exacerbation	$1,022	$794	$685	$507

Fuel COBRA Emissions Year DTE Emissions Year	Cummulative Impacts of Coal Units 1 & 2 2023-2026
$ Total Health Impacts (low estimate)	$2,510,139,318
$ Total Health Impacts (high estimate)	$5,660,664,879
Mortality(low estimate)	225
$ Mortality(low estimate)	$2,471,436,364
Mortality(high estimate)	510
$ Mortality(high estimate)	$5,590,197,616
Infant Mortality	1
$ Infant Mortality	$12,490,056
Nonfatal Heart Attacks(low estimate)	24
$ Nonfatal Heart Attacks(low estimate)	$3,837,479
Nonfatal Heart Attacks(high estimate)	222
$ Nonfatal Heart Attacks(high estimate)	$35,601,787
Hospital Admits, All Respiratory	54
Hospital Admits All Respiratory Direct	38
Hospital Admits, Asthma	4
Hospital Admits, Chronic Lung Disease	12
$ Hospital Admits, All Respiratory	$1,977,391
Hospital Admits, Cardiovascular(except heart attacks)	54
$ Hospital Admits, Cardiovascular (except heart attacks)	$2,769,943
Acute Bronchitis	250
$ Acute Bronchitis	$154,613
Upper Respiratory Symptoms	4,535
$ Upper Respiratory Symptoms	$193,942
Lower Respiratory Symptoms	3,184
$ Lower Respiratory Symptoms	$86,081
Emergency Room Visits, Asthma	106
$ Emergency Room Visits, Asthma	$59,807
Minor Restricted Activity Days	138,163
$ Minor Restricted Activity Days	$12,123,318
Work Loss Days	23,270
$ Work Loss Days	$4,658,355
Asthma Exacerbation	4,738
Asthma Exacerbation, Cough	1,076
Asthma Exacerbation, Shortness of Breath	1,449
Asthma Exacerbation, Wheeze	2,214
$ Asthma Exacerbation	$351,968

Fuel COBRA Emissions Year DTE Emissions Year	Cummulative Impacts of Gas Units 1 & 2 2027-2039	Coal 2023 10% scale down for 2023
$ Total Health Impacts (low estimate)	$134,942,611	$79,608,915
$ Total Health Impacts (high estimate)	$304,319,864	$179,615,530
Mortality(low estimate)	12	7
$ Mortality(low estimate)	$133,077,920	$78,372,849
Mortality(high estimate)	27	16
$ Mortality(high estimate)	$300,823,469	$177,367,339
Infant Mortality	0	0
$ Infant Mortality	$581,395	$399,993
Nonfatal Heart Attacks(low estimate)	1	1
$ Nonfatal Heart Attacks(low estimate)	$196,794	$122,084
Nonfatal Heart Attacks(high estimate)	12	7
$ Nonfatal Heart Attacks(high estimate)	$1,828,499	$1,134,209
Hospital Admits, All Respiratory	3	2
Hospital Admits All Respiratory Direct	2	1
Hospital Admits, Asthma	0	0
Hospital Admits, Chronic Lung Disease	1	0
$ Hospital Admits, All Respiratory	$103,477	$62,772
Hospital Admits, Cardiovascular(except heart attacks)	3	2
$ Hospital Admits, Cardiovascular (except heart attacks)	$143,061	$88,004
Acute Bronchitis	13	8
$ Acute Bronchitis	$7,867	$4,916
Upper Respiratory Symptoms	229	144
$ Upper Respiratory Symptoms	$9,884	$6,159
Lower Respiratory Symptoms	160	101
$ Lower Respiratory Symptoms	$4,383	$2,736
Emergency Room Visits, Asthma	5	3
$ Emergency Room Visits, Asthma	$2,879	$1,908
Minor Restricted Activity Days	6,506	4,419
$ Minor Restricted Activity Days	$577,266	$387,381
Work Loss Days	1,101	744
$ Work Loss Days	$220,325	$148,908
Asthma Exacerbation	231	151
Asthma Exacerbation, Cough	52	34
Asthma Exacerbation, Shortness of Breath	71	46
Asthma Exacerbation, Wheeze	108	71
$ Asthma Exacerbation	$17,361	$11,206

	Belle River Power Plant
Latitude, Longitude	42.7756, -82.495
Census Tract	Census Tract 26147641000 in St. Clair Cou
MIEJScreen Results	
MiEJ Score Percentile	15
Climate and Environmental Justice Screening Tool Results	
Identified as disadvantaged?	No

	Blue Water Energy Center
Latitude, Longitude	42.775527,-82.479064
Census Tract	Census Tract 26147643000 in St. Clair Cou
MIEJScreen Results	
MiEJ Score Percentile	52
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Colfax Peakers
Latitude, Longitude	42.6587, -84.0952
Census Tract	Census Tract 26093722100 in Livingston Cour
MIEJScreen Results	
MiEJ Score Percentile	15
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Dean Peaker
Latitude, Longitude	42.7725, -82.4953
Census Tract	Census Tract 26147641000 in St. Clair Cou
MIEJScreen Results	
MiEJ Score Percentile	15
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Dearborn Energy Center
Latitude, Longitude	42.2969, -83.2313
Census Tract	Census Tract 26163575400 in Wayne Cou
MIEJScreen Results	
MiEJ Score Percentile	60
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Delray Peakers
Latitude, Longitude	42.2947, -83.1019
Census Tract	Census Tract 26163525000 in Wayne Cou
MIEJScreen Results	
MiEJ Score Percentile	99
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	Yes

	Fermi
Latitude, Longitude	41.9631, -83.2581
Census Tract	ensus Tract 26115831200 in Monroe County
MIEJScreen Results	
MiEJ Score Percentile	68
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	Yes

	Greenwood Energy Center
Latitude, Longitude	43.1056, -82.6964
Census Tract	Census Tract 26147655600 in St. Clair Cou
MIEJScreen Results	
MiEJ Score Percentile	14
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Hancock Peakers
Latitude, Longitude	42.5497, -83.4425
Census Tract	Census Tract 26125134800 in Oakland Cour
MIEJScreen Results	
MiEJ Score Percentile	50
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Monroe Power Plant
Latitude, Longitude	41.8906, -83.3464
Census Tract	Census Tract 26115831800 in Monroe Cour
MIEJScreen Results	
MiEJ Score Percentile	89
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	Yes

	Northeast Peakers
Latitude, Longitude	42.45, -83.0381
Census Tract	Census Tract 26099982200 in Macomb Cour
MIEJScreen Results	
MiEJ Score Percentile	61
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	Yes

	Oliver Peakers
Latitude, Longitude	43.8264, -83.2383
Census Tract	Census Tract 26063950600 in Huron Cour
MIEJScreen Results	
MiEJ Score Percentile	17
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	Yes

	Placid Peakers
Latitude, Longitude	42.7106, -83.4569
Census Tract	Census Tract 26125126400 in Oakland Cour
MIEJScreen Results	
MiEJ Score Percentile	24
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Putnam Peakers
Latitude, Longitude	42.7108, -83.4561
Census Tract	Census Tract 26125126400 in Oakland Cour
MIEJScreen Results	
MiEJ Score Percentile	24
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Renaissance Power Plant
Latitude, Longitude	43.1864, -84.8429
Census Tract	Census Tract 26117971000 in Montcalm Cour
MIEJScreen Results	
MiEJ Score Percentile	16
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	Yes

	River Rouge Power Plant
Latitude, Longitude	42.2739, -83.1119
Census Tract	Census Tract 26163985600 in Wayne Cou
MIEJScreen Results	
MiEJ Score Percentile	0
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Superior Peakers
Latitude, Longitude	42.2639, -83.6422
Census Tract	Census Tract 26161407000 in Washtenaw Cou
MIEJScreen Results	
MiEJ Score Percentile	34
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Trenton Channel Power Plant
Latitude, Longitude	42.1217, -83.1808
Census Tract	Census Tract 26163594400 in Wayne County
MIEJScreen Results	
MiEJ Score Percentile	77
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

	Wilmot Peakers
Latitude, Longitude	43.4566, -83.1889
Census Tract	Census Tract 26157000500 in Tuscola Cour
MIEJScreen Results	
MiEJ Score Percentile	21
Climate and Environmental Justice Screening Tool Resu	
Identified as disadvantaged?	No

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.	)))))	Docket No. U-21193 Administrative Law Judge Sharon Feldman

DIRECT TESTIMONY OF
BORATHA TAN

March 9, 2023

I. <u>BACKGROUND AND SUMMARY</u>

Q. Please state your name and business address.

A. My name is Boratha Tan. My business address is 1 S. Dearborn St, Chicago, IL 60603. However, I work virtually from home in Detroit, MI.

Q. By whom are you employed and in what capacity?

A. I serve as Regulatory Manager, Midwest for Vote Solar. I oversee policy development and implementation related to large scale and distributed solar generation in the region. I also review regulatory filings, perform technical analyses, and testify in commission proceedings on issues relating to solar generation.

Vote Solar is an independent 501(c)3 nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over 2,700 members in Michigan. Vote Solar is not a trade organization nor does it have corporate members.

Q. On whose behalf are you submitting this direct testimony?

A. I appear here in my capacity as an expert witness on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists and Vote Solar. I refer to these parties collectively in this case as the Clean Energy Organizations, or "CEO."

Q. Please summarize your qualifications, experience, and education.

A. I graduated from Villanova University, with a Bachelor of Science in Mechanical Engineering and a minor in Peace and Justice. I worked at Ford Motor Company for six years in various capacities within the Electrical Systems Engineering department of the company; my work included designing, prototyping, and testing various high voltage components for future electric vehicles. My team and I have a pending patent on AI-related tools for electric motors. I also graduated with a Master's in Public Policy from the University of Michigan. I have experience in different engineering and analysis tools, including Autodesk, MATLAB, Ansys, RStudio, and Stata.

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

A. No.

Q: Have you testified or provided comments in similar state regulatory proceedings?

A: No.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit CEO-18: Resume of Boratha Tan
- Exhibit CEO-19: dGen Step-By-Step Process
- Exhibit CEO-20: dGen results spreadsheet
- Exhibit CEO-21: Community Solar and Storage Resilience spreadsheet

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to (1) explain the distributed generation ("DG") adoption modeling, which the CEO and its modeling team utilized to model DG resources in Encompass and (2) explain the community solar and storage for resilience estimates which form the foundation of the Energy Equity Package which the CEO are modeling in conjunction with the Detroit Area Advocacy Organizations ("DAAO"). The data that I compiled and constructed was input into EnCompass by Witness Chelsea Hotaling with Energy Futures Group, who explains that process in more detail in her testimony. Likewise, the policy justifications for many of the choices that underlie this data are presented in the testimony of CEO witnesses William Kenworthy and James Gignac, and DAAO Witness Jackson Koeppel.

Q: Please summarize your conclusions and recommendations.

A: I recommended the following values be used as assumptions into the CEO's Encompass modeling:

1) The total, cumulative, DG adoption for residential and commercial customers is 1,631 MW (AC) by 2042.
2) The total community solar capacity needed for resilience is 539 MW.
3) The total battery storage needed for resilience is 581 MWh.

Recommendation 1 will be referenced in Witness Kenworthy's testimony as "DG as a Resource". Recommendations 2 and 3 will be referenced as the "Energy Equity Package" in other testimonies from the CEO.

My testimony will explain the foundational assumptions which were used to calculate these figures.

II. DGEN ADOPTION MODEL

Q: What is NREL's dGen model?

A: NREL's dGen model is an open-source software, created to provide DG adoption predictions based on widely used data from NREL and the EIA. The dGen model was developed to "analyze the key factors that will affect future market demand for distributed solar", as well as other renewable resource technologies in one modeling program.[1]

Q: Why was NREL's dGen model chosen to model DG adoption?

[1] https://www.nrel.gov/analysis/dgen/about-dgen.html

A: The CEO chose dGen because it provides market-predictive based solar adoption values better than other models we have used in past cases. dGen is a very powerful model. Data can be filtered at the national, state, or even local level. dGen also utilizes NREL's Annual Technology Baseline (ATB) data to make determinations on DG adoption. ATB data is important for modeling; not only does DTE's EnCompass Modeling utilizes the same data, ATB data is used regularly in the electricity and transportation sectors for their own scenario generation. The CEO determined that dGen, a great open-source program, is the best tool available to model scenarios on DG adoption in this IRP.

Q: Why do you recommend 1,631 MW of solar DG adoption?

A: Please refer to Kenworthy's Testimony on DG as a Resource for the foundation of the CEO approach to modeling DG. To model DG adoption in DTE's service territory, the CEO utilized "Distributed Generation Market Demand", also called "dGen", as explained above. The CEO ran dGen under an "incentive scenario" to see how dGen predicts DG adoption with an incentive in place. As explained in witness Kenworthy's testimony, the CEO selected a DG incentive level of $500 per kW; this incentive level would help improve the adoption of distributed generation, while being attractive to the EnCompass model. A $1000 per kW incentive was also modeled, but the CEO are not recommending that level of incentive.

Additionally, I provided Witness Koeppel with estimated DG adoption values in Highland Park, both from the $1000 and $500 per kW incentives. These values were: 3.86 MW under a $1000 per kW incentive, and 2.67 MW under a $500 per kW incentive.

Q: Why do you recommend 539 MW of community solar?

A: Access to low cost, reliable renewable energy is essential to a just energy transition. As part of the Energy Equity package to ensure a just energy transition, the parties included a significant expansion in community solar over the Company's PCA. The CEO would like to reduce energy cost burdens ("ECB") of those most impacted by rising energy costs. The CEO decided to scope the project to a population that did not have other means to access renewable energy. We determined that LMI renters in DTE's electric service territory would have immediate need for ECB relief, and community solar would dramatically reduce ECB. For more explanation on why the CEO chose LMI renters as our target demographic, please refer to witnesses James Gignac and Boris Lukanov. As part of the foundational calculations, I assumed that each LMI renter household would subscribe to 3kW of community solar. This value tracks with NREL's estimates on community solar subscriptions in 2022.

Q: What were the calculations performed to reach 539 MW?

A: Please refer to Exhibit CEO-21 (Community Solar and Storage Resilience Spreadsheet) for detailed calculations. Below are steps I performed to reach 539 MW.

A. I looked on DTE's website to determine which counties are in DTE's electric service territory.

B. Based on these counties, I used USA Census data to find the number of housing units (and by type), the percentage of occupied units and renters, and percentage of LMI reported.

C. After the total number of LMI renter households were determined, I multiplied this by 3kW (per the 3kW subscription assumptions) and found that 539 MW is necessary.

Q: What was the reasoning behind the annual community solar build-out graph?

A: The CEO believe the most accurate projection of this type of program involves a gradual ramp-up of installations. This allows the Company to gather learnings at the early stages of the build-out and apply best practices over time. This tracks with the feedback DAAO Witness Koeppel received in his focus groups around ramp-up of DTE initiatives in LMI areas. I projected a steady ramp-up of the community solar build-out, with a constant annual build starting in 2028.

Q: Why did you recommend 581 MW of battery storage?

A: As part of a broader effort to enact a just and equitable energy transition, the CEO and their coalition partners at DAAO believe that LMI DTE customers must have access to energy storage, which will counteract poor reliability in these areas. The CEO decided to scope the program to meet the needs of a particular vulnerable population (from an energy standpoint). Therefore, the CEO decided to address the inherent needs of electricity-dependent Medicare recipients. During extended power outages, these individuals suffer the most because their life-saving machines would run out of power. For a more detailed explanation, please refer to Witness Gignac's testimony.

Q: What were the calculations performed to reach 581 MWh?

A: Please refer to Exhibit CEO-21 (Community Solar and Storage Resilience Spreadsheet) for detailed calculations. Below are steps I performed to reach 581 MWh.

A. The energy consumption of an at-home dialysis machine, stairlift, oxygen concentrator, and refrigerator were calculated with an 8-hour cycle and a 24-hour cycle.

B. I used the HHS empower Map (https://empowerprogram.hhs.gov/empowermap) to estimate the number of electricity-dependent Medicare recipients within DTE's electric service territory. This calculation showed that there are about 50,000 such individuals.

C. I chose the 8-hour cycle for further calculations. By multiplying this cycle (11.6 kWh) with over 50,000 customers, I found that 581 MWh is needed.

Q: What was the reasoning behind the annual storage build-out graph?

A: The CEO believe that there are various factors that still limit maximum build-out (including, but not limited to, materials shortage, labor shortage, etc.). The CEO projected a steady ramp-up of the battery storage build-out, with a constant annual build starting in 2029. Not only will this consider the factors listed above, but it will also track with Witness Koeppel's testimony on ramp-up of DTE initiatives.

Q: Is there anything else you would like to provide for your testimony?

A: Yes; as a Detroit resident who owns rooftop solar and battery storage, I know the immense value they provide to me and my community. During power outages, I invited my neighbors to charge their phones and backup batteries. I have also stored some perishables in my fridge on behalf of my neighbors. Distributed Generation as a Resource works for me, and it works for communities. As stated by Witness Kenworthy, not only does DG as a Resource benefit DTE, but it also promotes environmental and energy justice for communities such as mine.

Q: Does this end your testimony?

A: Yes, it does.

Boratha Tan
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Personal: Boratha@umich.edu

Education

University of Michigan, Gerald R. Ford School of Public Policy — Ann Arbor, MI
Master of Public Policy — Dec 2022

Relevant Coursework: Cybersecurity for Future Leaders, Science and Technology Policy, Public Management, Sustainable Energy Systems, Narrative Advocacy & Policy Change

Villanova University — Villanova, PA
Bachelor of Science Mechanical Engineering — May 2016
Minor: Peace and Justice Education

Professional Experience

Vote Solar — Detroit, MI
-*Regulatory Manager, Midwest* — Dec 2022 to Present

- Lead modeling studies of distributed generation assumptions in utility cases
- Work with non-profit stakeholders to promote cleaner, more affordable energy for low-income families
- Participate in utility rate cases, resource cases, and grid reliability cases in Michigan, Illinois, and Minnesota

National Conference of State Legislatures — Denver, CO
-*Policy Analyst Intern*, Environment, Energy, and Transportation — May 2022 to Aug 2022

- Provide state legislators with regional energy policies
- Support research requests on energy policy
- Lead program deliverables for the Department of Energy
- Support energy program planning and logistics for state legislators

Candidate, US House of Representatives — Detroit, MI
-*Michigan 13th District Candidate* — May 2022

- Write-in campaign for the August 2022 Primary

Ford Motor Company — Dearborn, MI
-*Core Electric Drive Engineer*, Electrified Systems Engineering — Jan 2019 to Apr 2022

- Lead early prototype builds, testing of future products
    - Delivered motor results critical to program progression
- Oversee early prototype timeline
- Manage later-stage prototype testing
    - Led root-cause analysis of first in-house motor
- Lead cross-functional team lessons learned meetings

-*Ford College Graduate Engineer*, Electrified Systems Engineering — Jul 2016 to Jan 2019

- Core high voltage battery engineer, future battery packs
- Core motor engineer, motor design
- Design and release engineer, Ford Escape Hybrid and Lincoln Corsair

Golden West Humanitarian Foundation
-*Research Engineer*, Cambodia Field Office — May 2016 to July 2016

- Lead in-field testing and troubleshooting of low-cost Explosive Ordnance Disposal Robot

Leadership and Service

University of Michigan Rackham Graduate School
-*Student Government Sustainability Officer* Aug 2022 to Apr 2023
- Lead sustainability programs for UofM graduate students

Villanova College of Engineering
-*Board Member,* Young Alumni Board Oct 2021 to Present
- Provide recommendations on the College's mission
- Promote DEI initiatives within the College

Detroit Design Core (DDC)
-*DDC Design Challenge Advisor* Mar 2021 to Mar 2022
- Facilitate design thinking sessions with non-profits
- Provide technical input on non-profit projects

Villanova Alumni Association
-*Vice President,* Club of Michigan Feb 2021 to Present
- Support planning for professional development and social events for local alumni
- Lead new programs to engage regional alumni

Freedom House Detroit
-*Fundraising Committee* Jan 2021 to Oct 2021
- Lead production crew for hybrid programming

Community Action Network (CAN)
-*Advisor* Feb 2020 to June 2020
- Provide input for STEM activities, which were implemented in summer programs

Contemplative Leaders in Action (CLA)
-*Detroit Cohort* Aug 2018 to Apr 2020
- Incorporate Ignatian contemplation into leadership
- Create a design of an early childhood reading program for local parish

Ss. Peter and Paul Jesuit Church
-*Parish Council and Social Justice Committee* Feb 2017 to Present
- Lead town halls for community input
- Support strategic plan development
- Lead DEI events for parish
- Participate in ecumenical meetings to address city's inequality

Thirty Under 30
-*Ford Cohort* Jan 2017 to Dec 2017
- Incorporate human-centered design into non-profit outreach

FIRST Robotics
-*Mentor,* Hamtramck High School Jan 2017 to Mar 2021
- Mentor high school students in robotics program

Skills

Additional Language: Khmer (native speaking)
Software & Apps: Arduino, MATLAB, R (RStudio), SOLIDWORKS, Autodesk, Microsoft Office, Westlaw, State Net (LexisNexis), Python

Awards

Non-destructive E-Motor Analysis – US Patent Office (Pending) 2022
Rev. Ray Jackson Community Service Award – Villanova University 2021
Illuminating Innovation and Excellence Award – Ford Motor Company 2021

Regulatory Cases

Michigan

-*U-21193 (DTE IRP 2022)*

1. dGen was released by NREL on its GitHub site[1]. I followed the README.md file to install dGen to a 2022 Apple MacBook Pro (M1 processor).
2. I followed the "Get Your Tools" section of the README file to download relevant programs. I downloaded RStudio to the Macbook in order to access the Terminal prompts.
3. In section B, under the "Running and Configuring dGen" portion of the README file, I downloaded relevant files for Michigan. I followed the information to move these Michigan files to the relevant folders for the dGen run.
4. In the dGen folders, I navigated to the "input_data" folder and found that the ATB inputs were dated 2019. I updated these csv files to 2021:
   a. Batt_tech_performance_FY19.csv
      1. This file is located in the batt_tech_performance folder
      ii. Update link: https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage
      iii. Update link: https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf
         1. Page 22; 86%
   b. ATB19_Mid_Case_retail.csv
      1. File located in the elec_prices folder
      ii. Update link: https://scenarioviewer.nrel.gov/?project=a3e2f719-dd5a-4c3e-9bbf-f24fef563f45&mode=download&layout=Default

[1] https://github.com/NREL/dgen

1. dGen model needs $/kWh in 2014 dollars, so I used the Bureau of Labor stats to see the inflation rate and calculate 2014 dollars from 2021 dollars
2. Link here: https://www.bls.gov/data/inflation_calculator.htm (Input: $1 in Jan 2021 is the same as what value in Dec 2014? Output is $0.90)

c. Financing_atb_FY19.csv
    1. File located in the financing_terms folder
    ii. Data retrieved from 2021_atb_data_master_mac_new file:
        1. Update link: https://data.openei.org/submissions/4129
        2. This spreadsheet lists 1.5% interest rate, so I used this value for years 2020 onwards

d. Pv_price_atb19_mid.csv
    1. File located in pv_prices folder
    ii. Data retrieved from 2021_atb_master_mac_new file
        1. I used Class 5 data to update this file, since NREL also uses Class 5
        2. Update link: https://atb.nrel.gov/electricity/2022/utility-scale_pv

e. ATB19_Mid_Case_wholesale.csv
    1. File located in wholesale_electricity_prices folder
    ii. Update link: https://scenarioviewer.nrel.gov/?project=a3e2f719-dd5a-4c3e-9bbf-f24fef563f45&mode=download&layout=Default
    iii. Update link: https://www.nrel.gov/docs/fy22osti/81611.pdf

5. dGen was run with these updated inputs, and no change to the solar investment tax credit ("ITC"). This decision was made to reflect DTE's modeling decision to exclude the Inflation Reduction Act's new solar ITC[2] . Please note that dGen can only run residential inputs and commercial inputs separately, so there will be two outputs to analyze. This run was to prove out dGen's assumptions.
6. In order to get dGen's outputs to mirror DTE's DG base assumptions, the input files were further modified to get similar base assumptions. I wanted dGen's assumptions to mirror DTE's DG base assumptions because we would like to see how the $1000 per kW incentive could affect DG adoption, on top of this base assumption.
7. Once dGen's outputs were on par with DTE's DG base assumptions, I added the $1000 per kW incentive to the pv_price file. This incentive was used to subtract the cost of residential, commercial, and industrial PV.
8. I re-ran dGen with the incentive inputs for residential and commercial runs.
9. With both residential and commercial output files, I navigated to the cumulative solar adoption column and pulled out the annual, incremental DG adoption values. These values are used for the EnCompass model inputs.
10. Repeat steps 7 to 9 for a $500 per kW incentive.

[2] MBL-pg.18, Q25.

Incremental DG (back calculated from Cumulative Table)				
	incremental (	incremental (	incremental (MW AC)	
	$0/kW	*$500/kW*	*$1000/kW*	
	USE DTE Inputs			
2022		*0*	*0*	*DTE's DG
2023		*0*	*0*	*DTE's DG
2024		*169*	*213*	
2025		*65*	*117*	
2026		*66*	*116*	
2027		*54*	*189*	
2028		*55*	*189*	
2029		*133*	*321*	
2030		*133*	*322*	
2031		*72*	*305*	
2032		*71*	*307*	
2033		*17*	*37*	
2034		*19*	*38*	
2035		*51*	*94*	
2036		*50*	*95*	
2037		*0*	*21*	
2038		*0*	*21*	
2039		*147*	*507*	
2040		*148*	*506*	
2041		*148*	*506*	
2042		*148*	*506*	

Cumulative DG (from dGen Model, in MW)				
	(MW AC)	(MW AC)	(MW AC)	
	$0/kW	*$500/kW*	*$1000/kW*	
	USE DTE Inputs			
2022		*71*	*71*	*DTE's DG
2023		*85*	*85*	*DTE's DG
2024		*254*	*298*	
2025		*319*	*415*	
2026		*385*	*531*	
2027		*439*	*720*	
2028		*494*	*909*	
2029		*627*	*1230*	
2030		*760*	*1552*	
2031		*832*	*1857*	
2032		*903*	*2164*	
2033		*920*	*2201*	
2034		*939*	*2239*	
2035		*990*	*2333*	
2036		*1040*	*2428*	
2037		*1040*	*2449*	
2038		*1040*	*2470*	
2039		*1187*	*2977*	
2040		*1335*	*3483*	*dGen modeling ends at 2040
2041		*1483*	*3989*	
2042		*1631*	*4495*	

Incremental DG (back calculated from Cumulative Table)

	incremental (	incremental (	incremental (MW AC)
	$0/kW	*$500/kW*	*$1000/kW*
	USE DTE Inputs		
2022		*56*	*53*
2023		*17*	*19*
2024		*17*	*19*
2025		*25*	*28*
2026		*26*	*28*
2027		*41*	*40*
2028		*41*	*41*
2029		*62*	*65*
2030		*62*	*66*
2031		*70*	*95*
2032		*69*	*96*
2033		*17*	*35*
2034		*18*	*35*
2035		*50*	*83*
2036		*49*	*84*
2037		*0*	*21*
2038		*0*	*21*
2039		*144*	*220*
2040		*145*	*220*

Cumulative DG (from dGen Model, in MW)

	(MW AC)	(MW AC)	(MW AC)
	$0/kW	*$500/kW*	*$1000/kW*
	USE DTE Inputs		
2022		*56*	*53*
2023		*73*	*72*
2024		*90*	*91*
2025		*115*	*119*
2026		*141*	*147*
2027		*182*	*187*
2028		*223*	*228*
2029		*285*	*293*
2030		*347*	*359*
2031		*417*	*454*
2032		*486*	*550*
2033		*503*	*585*
2034		*521*	*620*
2035		*571*	*703*
2036		*620*	*787*
2037		*620*	*808*
2038		*620*	*829*
2039		*764*	*1049*
2040		*909*	*1269*

*2022 and 2023 will be left out from EnCompass

Incremental DG (back calculated from Cumulative Table)

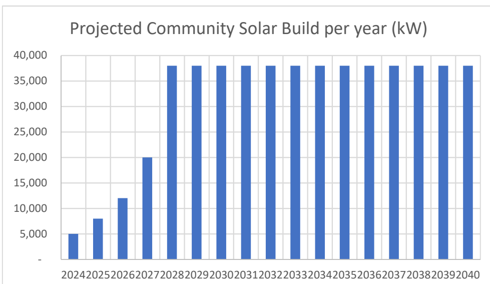
	incremental (	incremental (	incremental (MW AC)
	$0/kW	*$500/kW*	*$1000/kW*
	USE DTE Inputs		
2022		*130*	*112*
2023		*17*	*47*
2024		*17*	*48*
2025		*40*	*89*
2026		*40*	*88*
2027		*13*	*149*
2028		*14*	*148*
2029		*71*	*256*
2030		*71*	*256*
2031		*2*	*210*
2032		*2*	*211*
2033		*0*	*2*
2034		*1*	*3*
2035		*1*	*11*
2036		*1*	*11*
2037		*0*	*0*
2038		*0*	*0*
2039		*3*	*287*
2040		*3*	*286*

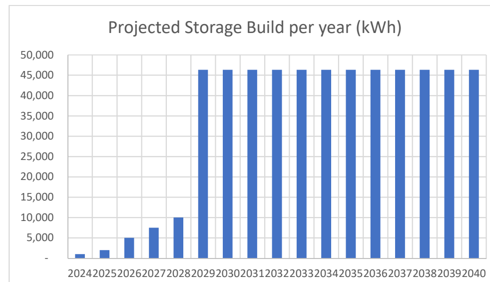
Cumulative DG (from dGen Model, in MW)

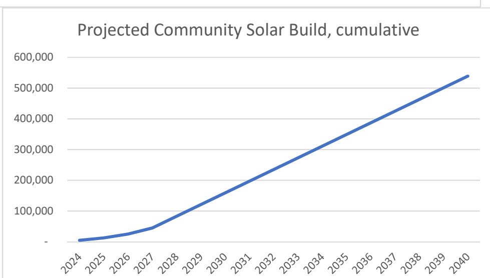
	(MW AC)	(MW AC)	(MW AC)	
	$0/kW	*$500/kW*	*$1000/kW*	
	USE DTE Inputs			
2022		*130*	*112*	
2023		*147*	*159*	*2022 and 2023 will be left out from EnCompass
2024		*164*	*207*	
2025		*204*	*296*	
2026		*244*	*384*	
2027		*257*	*533*	
2028		*271*	*681*	
2029		*342*	*937*	
2030		*413*	*1193*	
2031		*415*	*1403*	
2032		*417*	*1614*	
2033		*417*	*1616*	
2034		*418*	*1619*	
2035		*419*	*1630*	
2036		*420*	*1641*	
2037		*420*	*1641*	
2038		*420*	*1641*	
2039		*423*	*1928*	
2040		*426*	*2214*	

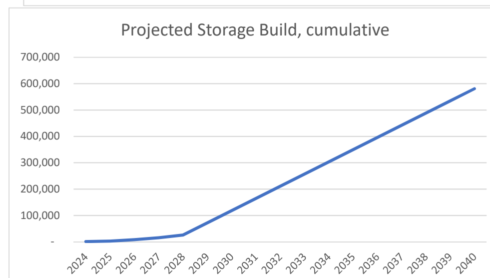
Community Solar Input for Encompass		
Year	Projected Community Solar Build per year (kW)	Projected Community Solar Build, cumulative
2024	5,000	5,000
2025	8,000	13,000
2026	12,000	25,000
2027	20,000	45,000
2028	38,000	83,000
2029	38,000	121,000
2030	38,000	159,000
2031	38,000	197,000
2032	38,000	235,000
2033	38,000	273,000
2034	38,000	311,000
2035	38,000	349,000
2036	38,000	387,000
2037	38,000	425,000
2038	38,000	463,000
2039	38,000	501,000
2040	38,000	539,000

Battery Storage (for Medicare, Electricity Dep) Inputs		
Year	Projected Storage Build per year (kWh)	Projected Storage Build, cumulative
2024	1,000	1,000
2025	2,000	3,000
2026	5,000	8,000
2027	7,500	15,500
2028	10,000	25,500
2029	46,300	71,800
2030	46,300	118,100
2031	46,300	164,400
2032	46,300	210,700
2033	46,300	257,000
2034	46,300	303,300
2035	46,300	349,600
2036	46,300	395,900
2037	46,300	442,200
2038	46,300	488,500
2039	46,300	534,800
2040	46,300	581,100





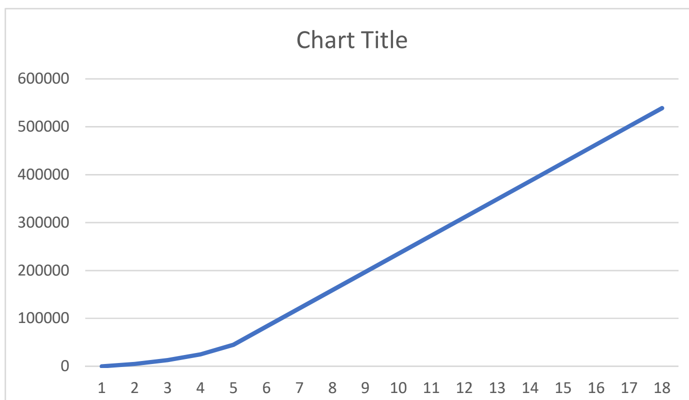




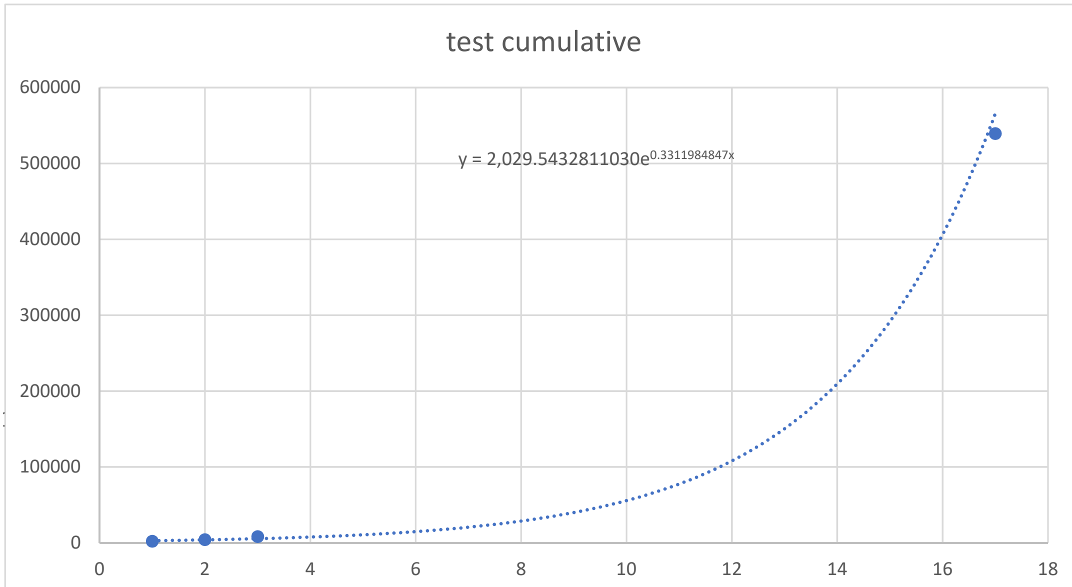
DTE Service Counties, MI	Total # of Housing Units	# of single units	# of multi units	# of mobile homes	# of other types	Estimated # of occupied, total	Estimated # of renter occupied, total	LMI county-level percentage	Estimated # of LMI Renter occupied (LMI on county-level)	kW of Community Solar (3 kW per LMI Renter)
Huron	20,443	17,785	1,431	1,431	-	13,492	2,564	48%	1,231	3,692
Lapeer	36,930	31,391	2,954	2,954	-	34,345	5,152	52%	2,679	8,037
Livingston	79,261	68,164	7,133	3,963	-	75,298	9,036	54%	4,879	14,638
Macomb	371,200	293,248	63,104	14,848	-	356,352	89,088	50%	44,366	133,097
Monroe	66,246	52,334	8,612	5,962	-	61,609	11,706	46%	5,361	16,084
Oakland	556,954	423,285	122,530	16,709	-	529,106	142,859	49%	69,429	208,288
Sanilac	21,833	18,121	1,528	2,183	-	17,030	3,406	48%	1,635	4,905
St. Clair	72,335	59,315	7,957	4,340	-	66,548	13,975	45%	6,317	18,950
Tuscola	23,994	19,915	1,680	2,159	-	21,355	3,203	49%	1,554	4,661
Washtenaw	157,960	99,515	53,706	4,739	-	148,482	57,908	46%	26,638	79,913
Wayne	791,100	601,236	174,042	15,822	-	94,932	33,226	47%	15,616	46,849
Total									179,704	539,113

* https://censusreporter.org/ used for all data

Year Increment	**Year**	**Projected Community Solar Build per year (kW)**	**Projected Community Solar Build, cumulative**	Linear (cum)	Policy. Driven	Cumulative
0	2023	0	0	0	0	0
1	2024	2000	2000	33695	5000	5000
2	2025	1500	3500	67390	8000	13000
3	2026	3500	5000	101085	12000	25000
4	2027	4134	7634	134780	20000	45000
5	2028	6497	10631	168475	38000	83000
6	2029	8308	14806	202170	38000	121000
7	2030	12311	20619	235865	38000	159000
8	2031	16404	28714	269560	38000	197000
9	2032	23585	39989	303255	38000	235000
10	2033	32105	55690	336950	38000	273000
11	2034	45451	77556	370645	38000	311000
12	2035	62556	108007	404340	38000	349000
13	2036	87858	150414	438035	38000	387000
14	2037	121614	209472	471730	38000	425000
15	2038	170104	291718	505425	38000	463000
16	2039	236153	406257	539120	38000	501000
17	2040	302960	539113	539113	38000	539000

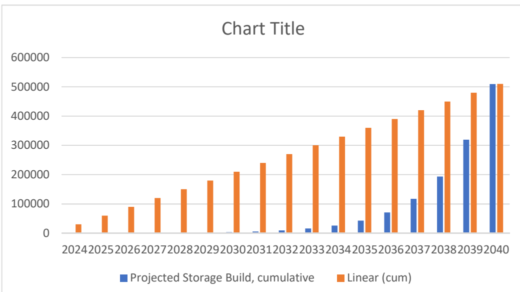


test year	test cumulative
0	0
1	2000
2	4000
3	8000
17	539113

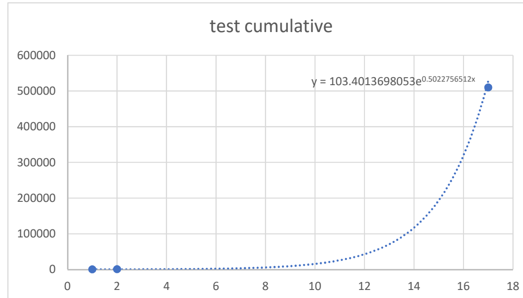


Machine	8 hr Consumption (kWh)	24 hr Consumption (kWh)
Home Dialysis	5.16	15.48
Stairlift	0.216	0.648
O2 Concentrator	4.8	14.4
Total	**10.2**	**30.5**
Estimated # of electricity-dependent Medicare customers:	50,089	
Estimated elec use for all EDM customers (kWh):	509,706	1,529,117

Year incremental	Year	Projected Storage Build per year (kWh)	Projected Storage Build, cumulative	Linear (cum)
1	2024	100	100	30000
2	2025	182	282	60000
3	2026	284	467	90000
4	2027	487	771	120000
5	2028	787	1274	150000
6	2029	1318	2105	180000
7	2030	2161	3479	210000
8	2031	3588	5749	240000
9	2032	5912	9500	270000
10	2033	9787	15699	300000
11	2034	16156	25943	330000
12	2035	26714	42870	360000
13	2036	44127	70842	390000
14	2037	72937	117064	420000
15	2038	120509	193446	450000
16	2039	199156	319665	480000
17	2040	310550	509706	510000



test year	test cumulative
1	100
2	500
17	509706



0	29982.7059
17	

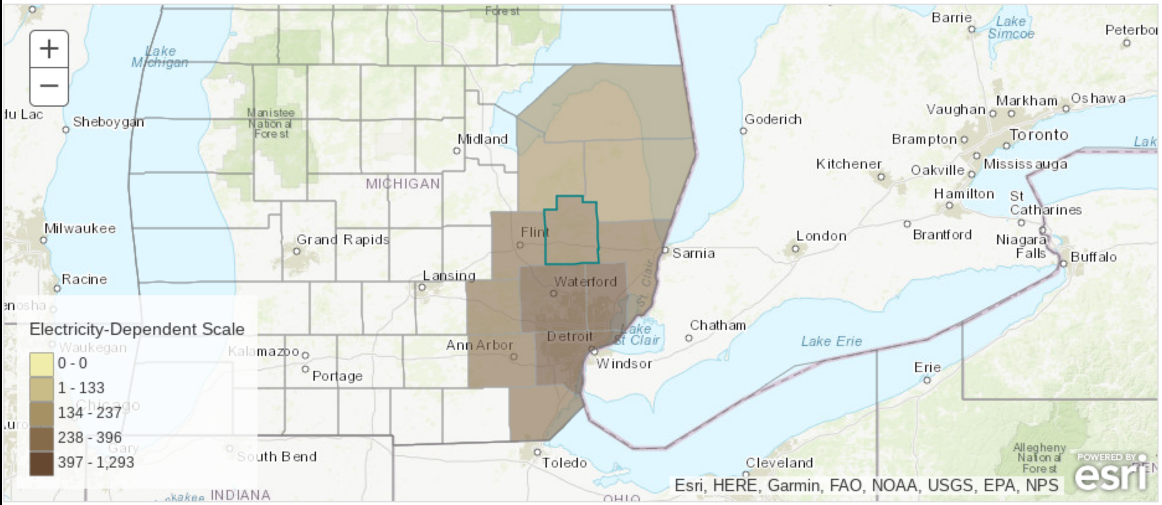
Machine	8 hr Consumption (kWh)	24 hr Consumption (kWh)
Home Dialysis	5.16	15.48
Stairlift	0.216	0.648
O2 Concentrator	4.8	14.4
Fridge	1.4	4.2
Total	**11.6**	**34.7**
Estimated # of electricity-dependent Medicare customers:	50,089	
Estimated elec use for all EDM customers (kWh):	580,105	1,740,314

Year	Projected Storage Build per year (kWh)	Projected Storage Build, cumulative	Policy Buildout	Cumulative	# of Customers	Cumulative Customers
2024	100	100	1,000	1,000	86	86
2025	182	282	2,000	3,000	173	259
2026	284	467	5,000	8,000	432	691
2027	587	871	7,500	15,500	648	1,338
2028	787	1,374	10,000	25,500	863	2,202
2029	1,418	2,205	46,300	71,800	3,998	6,200
2030	2,161	3,579	46,300	118,100	3,998	10,197
2031	3,688	5,849	46,300	164,400	3,998	14,195
2032	5,912	9,600	46,300	210,700	3,998	18,193
2033	9,887	15,799	46,300	257,000	3,998	22,191
2034	16,156	26,043	46,300	303,300	3,998	26,188
2035	26,814	42,970	46,300	349,600	3,998	30,186
2036	44,127	70,942	46,300	395,900	3,998	34,184
2037	73,037	117,164	46,300	442,200	3,998	38,182
2038	120,509	193,546	46,300	488,500	3,998	42,179
2039	199,256	319,765	46,300	534,800	3,998	46,177
2040	380,849	580,105	46,300	581,100	3,998	50,175

46217.0604

SELECTED GEOGRAPHIES

Wayne ✖ Oakland ✖ Washtenaw ✖ Macomb ✖ Livingston ✖ Genesee ✖ Lapeer ✖ Saint Clair ✖ Sanilac ✖ Huron ✖ Tuscola ✖ Monroe ✖



Medicare Data Totals by Selected Geographies

Geography	Beneficiaries	Electricity-Dependent Beneficiaries
Wayne	335755	15664
Oakland	255832	10076
Washtenaw	60417	2005
Macomb	182653	8393
Livingston	34797	1358
Genesee	95333	5536
Lapeer	19994	1128
Saint Clair	38979	1980
Sanilac	10948	686
Huron	9710	514
Tuscola	14277	917
Monroe	36581	1832
TOTAL	1095276	50,089
	Storage cost/home	10,000
	Solar cost/home	11,000

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.	) Docket No. U-21193)) Administrative Law Judge) Sharon Feldman)

DIRECT TESTIMONY OF

KEVIN LUCAS

March 9, 2023

Table of Contents

List of Tables and Figures

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin Lucas. I am the Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association ("SEIA"). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

A2. I began my employment at SEIA in April 2017 as the Director of Rate Design. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 30% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. Founded in 1974, SEIA is a national trade association building a comprehensive vision for the Solar+ Decade through research, education and advocacy.

As Senior Director of Utility Regulation and Policy, I have developed testimony in rate cases on rate design and cost allocation, in integrated resource plans on resource selection and portfolio analysis, worked on net energy metering and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy ("Alliance") from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

Q3. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION?

A3. Yes. I have submitted multiple rounds of testimony in Cases U-18419 (DTE's 2017 CON proceeding),[1] U-20162 (DTE's rate case implementing the inflow/outflow distributed PV ("DPV") methodology),[2] U-20165 (Consumers Energy's 2018 IRP proceeding),[3] U-20471 (DTE's 2019 IRP proceeding),[4] U-20697 (Consumer Energy's 2020 rate case related to the inflow/outflow DPV methodology),[5] and U-20836 (DTE's 2022 rate case)[6]

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[1] *In the matter of the application of DTE Electric Company for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*

[2] *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.*

[3] *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*

[4] *In the matter of the application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.*

[5] *In the matter of the Application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.*

[6] *In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.*

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

A4. Yes. I have submitted testimony in rate cases, integrated resource plans, utility merger proceedings, and renewable portfolio and energy efficiency resource standards before the Arizona Corporation Commission, the Georgia Public Service Commission, the Maryland Public Service Commission, the Public Utility Commission of Nevada, the North Carolina Utilities Commission, the Public Service Commission of South Carolina, the Public Utility Commission of Texas, and the Virginia State Corporation Commission. My complete CV is attached to my testimony.[7]

Q5. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A5. My testimony is provided on behalf of Intervenors, the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar, who are collectively referred to in this case as the Clean Energy Organizations or CEO.

Q6. ARE YOU SPONSORING ANY EXHIBITS?

A6. Yes. I am sponsoring the following exhibits:

- Exhibit CEO-22: Kevin M. Lucas CV
- Exhibit CEO-23: *Carbon Capture and Sequestration (CCS) in the United States*, Congressional Research Service, October 2022
- Exhibit CEO-24: MNSCDE-1.3
- Exhibit CEO-25: *NETL's Updated Performance and Cost Estimates for Power Generation Facilities Equipped with Carbon Capture,* National Energy Technology Laboratory, U.S. Department of Energy, October 2022
- Exhibit CEO-26: *Winter Storm Elliott Overview,* PJM, January 2023
- Exhibit CEO-27: *Michigan Hosting Capacity Study,* ITC Michigan, 2021

[7] Exhibit CEO-22, Kevin M. Lucas CV.

- Exhibit CEO-28: *Beyond Wires: Using Advanced Transmission Technologies to Accelerate the Transition to Clean Energy*, Environmental Law & Policy Center, May 2021
- Exhibit CEO-29: *Interconnection Cost Analysis in the Midcontinent Independent System Operator (MISO) Territory*, Lawrence Berkeley National Laboratory, October 2022
- Exhibit CEO-30: *Lessons from the Front Line: Principles and Recommendations for Large-scale and Distributed Energy Interconnection Reform*, SEIA, June 14, 2022
- Exhibit CEO-31: *Comments of the Solar Energy Industries Association,* Docket No. RM22-14-000, October 13, 2022

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A7. I discuss the CEO's position on DTE Energy Company's ("DTE" or "the Company") proposal to retire coal operations at Belle River and repower the facility with methane gas. While the CEO do not oppose the proposal in this case, I discuss steps that could have been taken in the past that may have reduced the need for the conversion. I also offer considerations for DTE, the Commission, and all stakeholders to consider that may reduce the need for future fossil-fuel powered generation, such as the one DTE bookmarks for a mid-2030s deployment.

Q8. WHAT ARE YOUR CONCLUSIONS?

A8. DTE has belatedly arrived at the conclusion that shifting to a zero-carbon, renewable-driven power grid is the least risk, preferred course of action for its customers. In its application, DTE proposes further acceleration of coal unit retirements, substantially increases its planned wind and solar deployments, ramps up energy efficiency and demand response, and leverages energy storage and transmission upgrades to tie it all together. If these recommendations sound familiar, it is because this is the same approach that many of the parties of the CEO recommended in DTE's 2017 certificate of necessity case for a new natural gas combined cycle unit.[8]

We are pleased to see the progress that DTE has made since that case, where it argued that a diverse portfolio of renewable and demand-side management ("DSM") resources was an insufficient and too risky alternative to a new baseload methane gas combined cycle unit.[9] In that case, the Company's Reference Scenario included an underwhelming 600 MW (500 MW wind, 100 MW solar) of new renewables from 2021 to 2040.[10] In this case, the Company proposes 15,400 MW of renewables (8,900 MW wind and 6,500 MW solar) and 1,810 MW of battery storage between now and 2040.[11]

Despite this progress, there are still challenges ahead. As the Company notes, there is no longer doubt that renewable energy is a least-cost resource. In fact, if the modeling software was not constrained on how much renewables generation it could build, it was economic to "overbuild" wind and solar and sell the excess into the MISO wholesale market.[12] Instead, renewables face headwinds related to interconnection delays, supply chain challenges, land-use opposition, and siting and permitting obstacles. It is imperative that DTE, the Commission, and stakeholders work together to proactively address these present and emerging challenges to prevent delays in the Company's deployment plan.

The Company should take an aggressive, no-regrets approach to tackling these issues. If successful, these efforts may enable the Company to avoid future fossil-based resources, currently a placeholder for 2035 capacity needs. While there will be at least one and

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[8] See Direct Testimony of Kevin Lucas, Michael B. Jacobs, R. Thomas Beach, and Philip Jordan on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, the Union of Concerned Scientists, and Vote Solar, Case No. U-18419, January 12, 2018.
[9] "After taking into account planned renewables, energy efficiency, and demand response programs, the results of the IRP process indicate that, in the majority of the cases modeled, the Company's expected shortfall in energy and capacity would most prudently be addressed with the addition of a base-load combined cycle gas turbine generating plant sized at approximately 1,100 MW with demand response and minor market purchases or other resources up to 300 MW being used to make up any remaining energy and capacity needs." Qualifications and Direct Testimony of I.M. Dimitry at 20, DTE Electric Company, Case U-18419.
[10] Qualifications and Direct Testimony of K.J. Chreston at 46, DTE Electric Company, Case U-18419.
[11] Exhibit A.31 Part 2 at 49.
[12] Qualifications and Direct Testimony of Vielka M. Hernandez at 21.

probably two more IRP cycle prior to that decision, steps taken now will directly impact whether avoiding this resource will be possible or not.

We know today that working towards a future resource mix with even more renewables, DSM, and storage that avoids new fossil-based resources with carbon capture and sequestration ("CCS") mitigates several risk vectors. CCS technology has not been commercialized in the U.S. electric power sector, and many questions remain about its technical, much less economic, viability. As we have seen in the past year, methane gas costs can dramatically increase, leading to substantially higher bills for customers. This fuel price volatility risk simply does not exist for wind and solar generation. And unfortunately, methane gas generators have proven to be unreliable in extreme weather conditions, with correlated outages plaguing utilities across the country in the past several years.

It is now a given that substantial new renewable capacity will be central to all future scenarios. DTE should shift towards a "build it and they will come" mentality, working proactively with stakeholders to analyze its system with an eye towards maximizing cost-effective renewable energy interconnection. Starting with the needed analyses now will provide insight to resources looking at this PCA, but can also provide direction to the industry on where future capacity may be able to easily interconnect. The Company knows its system best and is well-positioned to partner with ITC Transmission and work with MISO to determine where relatively minor distribution and transmission upgrades could unlock many megawatts or gigawatts of renewable capacity.

II. CEO'S POSITION ON BELLE RIVER AND INTERCONNECTION REFORMS

Q9. WHEN DID DTE BEGIN WORK ON THE POTENTIAL CONVERSION OF BELLE RIVER TO METHANE GAS?

A9. Engineering work began in 2020, well in advance of this docket, with a planned online date of 2026.[13]

Q10. IS IT POSSIBLE THAT THE COMPANY COULD HAVE FOUND A DIFFERENT SOLUTION HAD IT STARTED WORKING ON FILLING THIS CAPACITY NEED EARLIER?

A10. Yes, it is possible. While it may have been difficult to have fully avoided the Belle River conversion, had parties begun in earnest on a clean energy portfolio in 2020, it may have been possible to have retired an additional unit at Belle River and only converted one of the coal units to methane gas, saving ratepayers money. As ELPC et al. pointed out in the 2019 IRP docket, DTE advanced a circular argument regarding capacity need. In this argument, as long as DTE had an IRP that met future capacity shortfalls, it never had a capacity "need" – even if it was projected to be short on capacity.[14,15] This led to lower prices in its various PURPA proceedings, which led to fewer resources responding to a price signal that could have brought more PURPA resources on line.[16] However, at this point, it would be very hard to develop an alternative to this conversion while still retiring the Monroe units in 2028.[17]

Q6. GIVEN THIS, WHAT IS CEO'S POSITION ON DTE'S PROPOSAL TO RETIRE COAL OPERATIONS AT BELLE RIVER AND REPOWER THE FACILITY WITH METHANE GAS?

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[13] Qualifications and Direct Testimony of Justin L. Morren at 20.

[14] "Because DTE hardcoded in so many resources, the Company claims it will not have a 'capacity need' within the IRP period. This has a crucial impact on the analysis because DTE configured Strategist to only allow new, lower cost resources where there is a capacity need. DTE prevented the model from adding what DTE labels 'superfluous' resources even though so-called 'superfluous' resources could help reduce the overall cost of DTE's plan by pushing out higher-cost resources before DTE's hardcoded retirement dates." ELPC Brief at 12, Docket U-20471.

[15] "under any method for determining capacity need, DTE designed its model to ensure that DTE will not show a capacity need until Belle River is retired." ELPC et al. Brief at 15, Docket U-20471.

[16] "Mr. Jester explains that DTE is using the same PURPA strategy in this IRP case that allowed the Company to seek approval to construct a new 1,100 MW gas plant while simultaneously arguing that it had no PURPA capacity need." ELPC et al. Brief at 16, Docket U-20471.

[17] "To the extent that the Commission reaches a conclusion regarding DTE's capacity need in this case, Mr. Jester points out that resources used to fill future capacity needs have years-long ram-up times." ELPC et al. Brief at 16, Docket U-20471.

A11. CEO does not oppose DTE's proposal for the conversion of these units as the most logical choice given the present circumstances. However, this lack of opposition is contingent on the addressing of equity concerns as discussed by CEO Witnesses Gignac and Kenworthy. The Belle River conversion would enable the Company to maintain a 1,270 MW capacity resource that would be operated as a peaking plant.[18] This capacity would be online by 2026, just as the Company's renewable resource deployment ramps up in earnest. The Company indicates that the conversion of Belle River is substantially less expensive than procuring a new gas-fired peaking unit, saving customers money.[19] It plans to operate the unit as a peaking resource, limiting carbon emissions, and proactively plans to retire the converted units by 2040.[20]

Further, the Company indicates that maintaining this capacity in MISO Zone 7 enables it to retire 1,535 MW of coal-fired resources at Monroe in 2028 – 12 years earlier than previously planned – leading to a substantial incremental carbon emission reduction.[21] As CEO Witness Bilsback testifies, the public health benefits of retiring one coal plant 2-3 years earlier and another coal plant 14 years earlier are immense, particularly when its methane gas replacement will only run at roughly a 10% capacity factor.[22] In aggregate, maintaining a sizable dispatchable capacity resource that will be used in limited circumstances while enabling the faster retirement of baseload coal generation is a reasonable tradeoff.

III. DTE'S PROPOSED CCGT WITH CCS

Q12. DOES THE COMPANY HAVE ANY PLACEHOLDERS FOR NEW DISPATCHABLE RESOURCES IN ITS PREFERRED COURSE OF ACTION?

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[18] DTE Application at 2.
[19] "[T]he Belle River conversion is one-sixth of the cost of a new combustion turbine (CT)…" Qualification and Direct Testimony of Joyce E. Leslie at 26-27.
[20] DTE Application at 2.
[21] Qualifications and Direct Testimony of Joyce E. Leslie at 15.
[22] Direct Testimony of Dr. Kelsey Bilsback.

A12. Yes, it does. The Company's modeling and analysis suggest a 946 MW facility may be needed in 2035. Its preferred course of action ("PCA") incorporates a 946 MW low or zero carbon, dispatchable resource in 2035 when the final two units (Units 1 and 2) of the Monroe Power Plant retire. While low and zero carbon dispatchable technologies to support net zero goals are still emerging and require further development, the technology currently selected in the IRP is a natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS).[23]

Q7. DOES CEO SUPPORT THIS ELEMENT OF THE COMPANY'S PCA?

A13. No. CEO strongly urges the Company and the Commission to pursue alternative approaches that would not require the construction of a new fossil-fuel powered plant paired with currently-uncommercialized CCS technology.[24] Steps should be taken now to avoid this facility if at all possible.

Q14. WHAT ARE SOME OF THE RISKS ASSOCIATED WITH THIS FUTURE FACILITY?

A14. There are several. The first and foremost is simply that power plants with CCS are not commercialized. The Company itself admits this, noting that it is "unaware" of any other IRP by any other utility that incorporates a NGCC with CCS or any utility that currently operates any generating unit with CCS.[25,26] The one power plant that in the past utilized carbon capture technology was uniquely situated in Texas with a ready and profitable use – enhanced oil recovery – for the captured CO_2. This facility was plagued with issues, including a high number of outages attributable to the CCS equipment.[27] Further, it was only

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[23] DTE Application at 3.
[24] While CCS technology has been deployed in several industrial facilities around the world, only one US power plant has been built with CCS, and it only operated for three years before shutting down the CCS equipment in 2020. Exhibit CEO-23, *Carbon Capture and Sequestration (CCS) in the United States*, Congressional Research Service, October 2022. Available at https://crsreports.congress.gov/product/pdf/R/R44902
[25] Exhibit CEO-24, MNSCDE-1.3a.
[26] Exhibit CEO-24, MNSCDE-1.3c.
[27] "Problems plagued U.S. CO2 capture project before shutdown: document", Reuters, https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-before-shutdown-document-idUSKCN2523K8

designed to capture one third of the emitted CO_2, much less than DTE's projected 90% or 98.5% facilities.[28]

Given that Michigan produces only 0.1% of the nation's oil, using the CO_2 for enhanced oil recovery is unlikely to be a viable use, particularly since the emissions from burning the oil would undo much of the benefit of capturing CO_2 in the first place.[29] Instead, the captured CO_2 will have to be geologically stored. This will require an entirely new set of infrastructure assets to capture, transport, and store the CO_2. Pipelines are notoriously difficult to approve and permit, particularly for a material categorized as "hazardous" that pose health and safety issues if a pipeline leaks or ruptures.[30] CO_2 pipelines have faced local opposition in other parts of the Midwest where CO_2 pipelines have been proposed.[31] While the Inflation Reduction Act has increased the value of the tax credit for CCS, the parasitic load of the CCS equipment – which can consume a significant portion of the NGCC's power output – will increase the levelized cost of electricity compared to alternatives.

Many hurdles would have to be overcome to successful deploy a NGCC project with CCS. CCS imposes heavy parasitic loads on the power plant, resulting in a less efficient facility that is more expensive to run than other fossil-fueled generation, much less zero-emission wind and solar. In fact, a recent U.S. Department of Energy report suggested that adding CCS to a NGCC could increase the levelized cost of electricity by more than 50% at a 95% capture rate, and even more for higher capture levels.[32] Permitting of pipelines and

[28] Qualifications and Direct Testimony of Laura K. Mikulan at 23.

[29] Michigan produced about 4.3 million barrels of oil in 2021, compared to U.S. production of 4,107 million barrels. https://www.eia.gov/dnav/pet/PET_CRD_CRPDN_ADC_MBBL_A.htm

[30] *Carbon Dioxide Pipelines: Safety Issues*, Congressional Research Service, June 2022. Available at https://crsreports.congress.gov/product/pdf/IN/IN11944

[31] "Advocates Elevate Concerns Over Navigator CO2 Ventures' Proposal to Transport High-Pressure, Liquified CO2 Through 13 Illinois Counties," RiverBender.com, March 9, 2022. Available at https://www.riverbender.com/articles/details/advocates-elevate-concerns-over-navigator-co2-ventures-proposal-to-transport-highpressure-liquified-co2-through-13-illinois-counties-57270.cfm

[32] Further, the LCOE is sensitive to capacity factor, with prices increasing as capacity factor falls. Given the expensive energy, unless DTE runs the unit out of merit, it will likely be dispatched less and fail to attain high capacity factors required to keep costs low. Exhibit CEO-25, *NETL's Updated Performance and Cost Estimates for Power Generation Facilities Equipped with Carbon Capture*, National Energy Technology Laboratory, U.S. Department of Energy, October 2022. Available at https://usea.org/sites/default/files/event-/USEA%20Webinar_FEB_Rev0_20230201.pdf

storage facilities will certainly face local opposition, and even if this can be overcome, will take many years to plan, permit, and construct. Assuming that all of these necessary puzzle pieces will fall neatly into place in time to have an operational NGCC with CCS in 2035 is very risky.

Additionally, adding more methane gas capacity will burden future ratepayers with volatile methane gas prices. This issue is sufficiently important to have been identified by the Michigan Legislature as one of the several IRP risk factors that the Commission is required to analyze when considering an IRP.[33] Utilities across the country are now reckoning with the impact of the huge price run up last year. Georgia Power has requested recovery of $2.1 billion in additional, incremental fuel charges that have already been spent.[34] If approved, these will increase bills between $17 and $23 per month. Utilities in western states such as California, Colorado, and Utah face similar issues, with some consumers "paying triple their normal amounts this winter"[35]

Renewable resources such as solar and wind have no fuel costs, and thus are completely insulated from this volatile commodity. In this way, they act as a hedge against commodity price volatility. Adding new generation that relies on unstable methane gas prices is a step in the wrong direction.

Unfortunately, DTE's core assumption that the new NGCC will provide reliable power because it does not rely on intermittent sunlight and wind has not been borne out in the past few years. Utilities and RTOs are reckoning with the reality that fossil-fuel powered plants face a strongly correlated outage risk. In the February 2021 winter storm Uri in Texas, widespread failures across the entire methane gas supply chain occurred, resulting in massive

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[33] One of the IRP evaluation factors is "commodity price risks" MCL 460.6t(8)(a)(v).

[34] "Georgia Power seeks recovery of fuel costs," Georgia Power Company, February 28, 2023. Available at https://www.georgiapower.com/company/news-center/2023-articles/georgia-power-seeks-recovery-of-fuel-costs.html

[35] "Why energy bills skyrocketed in the U.S. West," E&E News, February 21, 2023. Available at https://www.eenews.net/articles/why-energy-bills-skyrocketed-in-the-u-s-west/

outages at plants due to lack of fuel.[36] Less than two years later, another cold snap over Christmas 2022 resulted in widespread outages in the southeast, again largely due to the failure in fossil-fuel powered plants.[37] While PJM did not drop any load during this event, 46 GW or nearly 25% of its capacity was forced offline, with 32.5 GW of methane gas units failing.[38] Astoundingly, this represented nearly 40% of PJM's methane gas UCAP capacity for the delivery year.

IV. CEO'S PROPOSED RENEWABLUE BUILDOUT & INTERCONNECTION REFORM

Q15. WHAT IS CEO'S ALTERNATIVE TO BUILDING THIS FACILITY?

A15. Instead of building this facility, CEO propose incremental deployment of renewable energy and energy storage. As discussed by CEO witnesses Hotaling and Kenworthy, a modeled pathway increasing solar, wind, and battery deployment can reliably and economically meet DTE's needs.

Q16. DOES THIS APPROACH ELIMINATE ALL RISK COMPARED TO THE NGCC WITH CCS FACILITY?

A16. While it eliminates all of the specific risks associated with that facility's uncommercialized technology and ancillary industrial needs, there are still challenges in realizing CEO's alternative portfolio vision. Fortunately, these risks – and ways to mitigate them – are well known, and the Company, the Commission, and stakeholders can begin to take steps now that will increase the likelihood of success.

Q17. WHAT ARE SOME OF THESE RISKS?

A17. I group the risks into two categories. The first is technical, the second procedural. From a technical perspective, integrating the necessary quantity of renewable generation to avoid the NGCC with CCS facility will require upgrades to the transmission system and will need to

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[36] "Texas largely relies on natural gas for power. It wasn't ready for the extreme cold," Texas Tribune, February 16, 2021. Available at https://www.texastribune.org/2021/02/16/natural-gas-power-storm/

[37] "Winter storms put the US power grid to the test. It failed." Vox, December 27, 2022. Available at https://www.vox.com/energy-and-environment/2022/12/27/23527327/winter-storm-power-outages

[38] Exhibit CEO-26, *Winter Storm Elliott Overview*, PJM, January 2023. Available at https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx;

address identified reactive power issues.[39] From a procedural perspective, DTE and ITC must find ways to interconnect new facilities in a much more efficient and cost-effective manner.

Q18. HAS WORK BEEN DONE TO ADDRESS THE FIRST SET OF TECHNICAL ISSUES?

A18. Yes. While the CEO's portfolio does increase the quantity of renewable generation and storage, DTE's PCA already included a significant amount of these resources. As such, DTE worked with ITC through the development of the IRP to simulate the transmission system and identify potential issues with its PCA portfolio.[40] These analyses identified several transmission system upgrades that would be needed to maintain the system within the required operational tolerances under various build and retirement scenarios.[41]

ITC as also recently completed a hosting capacity analysis of its system as directed by the Commission.[42] This analysis shows that several areas of the state would be able to interconnect large quantities of new renewable generation with minimal upgrade costs. For example, ITC found that about 2 GW of systems could be interconnected in the Midland region for roughly $5 million, while 5 GW could be interconnected for roughly $110 million.[43] Similarly, the Central region would require roughly $60 million to interconnect 5 GW, while the South region would only require $5 million to interconnect 5 GW. Although many caveats surely exist for these studies, producing and updating robust hosting capacity maps will be critical to help steer projects to locations that minimize their costs and maximize the chance of a successful interconnection study.

One immediate option would be to reserve the interconnection capacity at retiring coal plants for new renewable and battery systems. These high-capacity transmission facilities already exist, and given they were built to serve continuous load from large

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[39] Qualifications and Direct Testimony of Sonjoy D. Roy at 21. ("Roy Direct")
[40] *Id.* at 9.
[41] *Id.* at 16.
[42] Exhibit CEO-27, *Michigan Hosting Capacity Study*, ITC Michigan, 2021. Available at https://www.oasis.oati.com/woa/docs/METC/METCdocs/MI_Hosting_Capacity_-_Final.pdf
[43] ITC notes that these costs are estimates and only include core system costs, not direct assigned costs for items such as generation lead lines or new interconnection substations.

facilities, there should be no or minimal interconnection costs. While it may not be possible to replace coal capacity on a 1:1 basis with renewable capacity, batteries have a much higher power density and may be able to replace the capacity on the same facility footprint.

Q19. ARE THERE POTENTIAL ALTERNATIVES TO THE TRADITIONAL MISO TRANSMISSION PLANNING APPROACH THAT MAY ENABLE THESE UPGRADES TO BE APPROVED PROSPECTIVELY?

A19. Yes. Michigan has embarked on a pathway to decarbonize its economy by 2050, as enshrined in the Michigan Healthy Climate Plan.[44] The long-term solution set *will* contain many gigawatts of wind, solar, and battery capacity, and these facilities will have to be integrated into the broader grid successfully. Given this, continued collaboration between DTE, ITC, the Commission, and policy makers to proactively identify and remediate transmission issues must become the norm.

One such approach been enacted in PJM at the bequest of New Jersey.[45] Dubbed the "State Agreement Approach" originally authorized through FERC Order 1000, this process allows a state to proactively sponsor – and critically, agree to pay for – a set of transmission projects that are designed to advance state policy goals. New Jersey utilized this approach to enable 7,500 MW of offshore wind to connect to PJM's grid. New Jersey worked with PJM for several years to identify the most cost-effective transmission solution, reviewing over 80 projects from 13 developers.

Given that the State Agreement Approach is authorized by FERC and now has precedent in PJM, Michigan could engage with MISO to implement a similar approach here. Together, the government of Michigan, DTE, Consumers Energy, ITC, and the Commission could work to develop a set of transmission projects that would optimize the state's grid to

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[44] *Michigan Healthy Climate Plan*, Michigan Department of Environment, Great Lakes, and Energy, April 2022, https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf

[45] "New Jersey Marks Milestone for Offshore Wind Using PJM's State Agreement Approach," PJM Inside Lines, October 26, 2022. Available at https://insidelines.pjm.com/new-jersey-marks-milestone-for-offshore-wind-using-pjms-state-agreement-approach

accommodate the many, many gigawatts of new resources that will be needed to meet Michigan's Healthy Climate Plan electricity sector goals.

Another critical element of this advocacy will be to include rigorous consideration of grid enhancing technologies that can improve the efficiency of the existing transmission system. For instance, new conductors, power flow controls, and dynamic line rating should be routinely considered as ways to squeeze more capacity out of the existing system with lower costs and faster deployment times to increase renewable integration.[46] As one report astutely observes, "This is not an 'either/or' choice between traditional large wires projects and new transmission technologies. Both are critical."[47]

Q20. HAS WORK BEEN DONE TO ADDRESS THE SECOND SET OF PROCEDURAL ISSUES REGARDING INTERCONNECTION?

A20. Yes, although more work is clearly needed as the interconnection issue has worsened significantly over the past several years. The Lawrence Berkeley National Laboratory ("LBNL") recently published a report detailing the degree of the degradation of the MISO interconnection queue process.[48] In this report, LBNL identified a significant increase in interconnection costs for both projects that have successfully made it through the queue, as well as for projects that have dropped out of the queue. Further, these cost increases have not been driven by the physical assets required to connect the new project to the grid, but rather "network" upgrade expenses to enhance parts of the transmission system that may be tens or hundreds of miles away from the actual interconnection locations.[49]

For projects that came online prior to 2019, the average interconnection cost was $58/kW. This nearly doubled to $102/kW for projects that came online between 2019 and

[46] Exhibit CEO-28, *Beyond Wires: Using Advanced Transmission Technologies to Accelerate the Transition to Clean Energy*, Environmental Law & Policy Center, May 2021. Available at https://elpc.org/wp-content/uploads/2021/05/BeyondWires_ELPC_Final2021.pdf
[47] Id.
[48] Exhibit CEO-29, *Interconnection Cost Analysis in the Midcontinent Independent System Operator (MISO) Territory*, Lawrence Berkeley National Laboratory, October 2022. Available at https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2022.10.06-_miso_interconnection_costs.pdf
[49] *Id.* at 3.

2021, and for projects still actively working through the queue, has ballooned further to $156/kW.[50] As difficult as these increases have been for project developers, they pale in comparison to the costs identified for projects that have withdrawn from the queue. Those costs have hovered around $450/kW for several years, and were simply too much for projects to absorb, forcing the project developer to cancel the project.[51]

Q21. WHAT PERCENTAGE OF THESE HIGH UPGRADE COSTS WERE FOR NETWORK UPGRADES?

A21. A significant portion, particularly for projects that have withdrawn from the queue. As seen below, the majority of costs for active projects and withdrawn projects is for broader network upgrades and not for point of interconnection ("POI") costs. Further, for many of these projects, these costs are actually for other transmission systems or RTOs entirely. LBNL notes that 27% of projects have had "affected system" interconnection costs that have averaged $127/kW.[52] It is difficult to find the fairness in a project in Michigan being charged for upgrades in Nebraska.

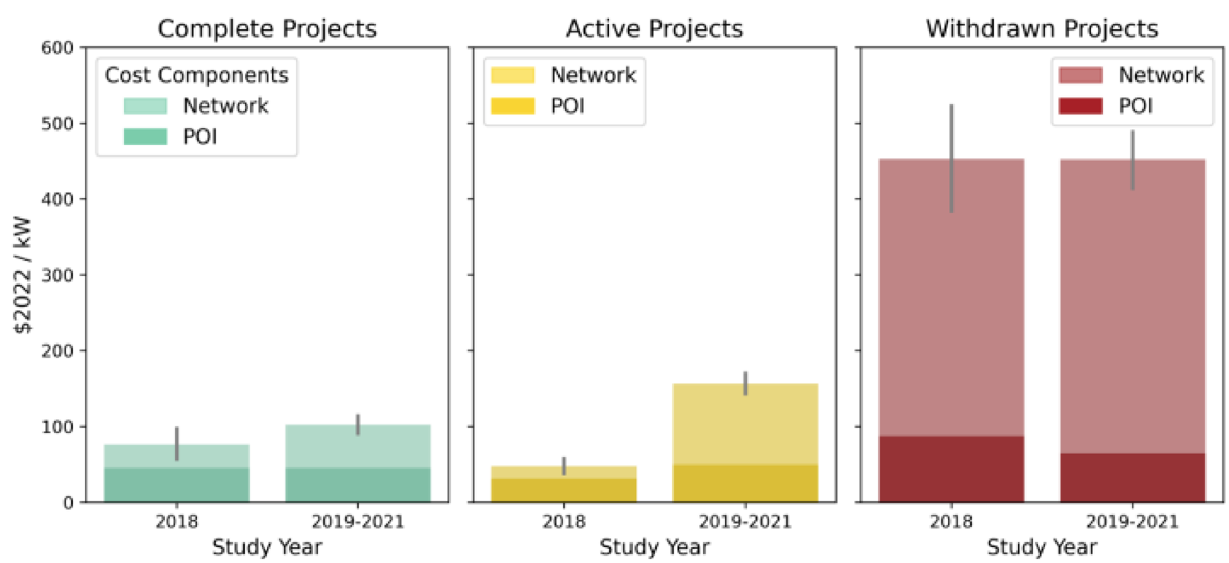

Figure 4 Interconnection Costs by Cost Category and Request Status *(bars: means, gray lines: standard error of total costs)*

Figure 1 - Network vs. POI Costs

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[50] *Id.* at 4-5.
[51] *Id.* at 5.
[52] *Id.*

Q22. HAS SEIA PROVIDED COMMENTS AND RECOMMENDATIONS ON HOW TO ADDRESS THESE ISSUES?

A22. Yes, SEIA has. SEIA published a whitepaper in June 2022 addressing some of these issues,[53] and also has commented in the FERC notice of proposed rulemaking (NOPR") on interconnection queue reform.[54] Common threads include increasing the transparency of the interconnection process (such as publicly publishing bus-level interconnection capacity constraints), increasing the efficiency and clarity of the cluster study process by providing cost estimates at each stage and limiting restudies, and avoiding commercial readiness requirements that are infeasible for developers to meet. The CEO recommend that DTE, ITC, the Commission, and other Michigan policy makers continue to actively and aggressively advocate for interconnection reforms that will help break the project backlog.

Q23. WHY IS IT IMPORTANT TO TAKE THESE EFFORTS NOW WHEN THEY ARE IN THE CONTEXT OF AVOIDING A FACILITY IN 2035?

A23. Because, as with many things related to the electricity industry, these changes will take time to implement. The SAA recently utilized in PJM is not available in MISO, and working through the stakeholder process needed to implement it may take years. Similarly, the interconnection queue reform NOPR still has to wend its way through FERC before being returned to MISO for implementation. Even at that point, there may be additional changes that are needed to truly unlock the capacity currently stuck in the interconnection queue.

The CEO have demonstrated a feasible solution that avoids the Company's planned NGCC with CCS in 2035 but recognize that steps must be taken to realize this future. The current grid and interconnection process cannot support the transition required in Michigan's Healthy Climate Plan. Transmission and distribution system upgrades will be required to

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[53] Exhibit CEO-30, *Lessons from the Front Line: Principles and Recommendations for Large-scale and Distributed Energy Interconnection Reform*, SEIA, June 14, 2022. Available at https://seia.org/research-resources/lessons-front-line-principles-and-recommendations-large-scale-and-distributed

[54] Exhibit CEO-31, *Comments of the Solar Energy Industries Association*, Docket No. RM22-14-000, October 13, 2022. Available at https://seia.org/sites/default/files/2022-10/SEIA%20IX%20NOPR%20Comments%2010.13.22.pdf

incorporate the many gigawatts of new renewable resources, and finding fair and efficient ways to fund these upgrades will be critical. Stakeholders should be focused on both distributed and grid scale solutions to this problem. The Commission must more urgently focus on its nascent integrated distribution planning process to accelerate grid investments to integrate large amounts of distributed energy resources.

We urge the Commission to direct DTE to take steps to eliminate as many barriers to efficient interconnection as possible. Further, it should direct Staff to identify new solutions that may not be within the Commission's current statutory authority but could nonetheless help improve the situation. These could be incorporated into new legislative efforts to support the Healthy Climate Plan.

Q24. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A24. The CEO do not oppose the conversion of Belle River to methane gas, so long as it is coupled with significant steps forward on energy equity, as discussed by CEO Witnesses Gignac and Kenworthy. Although the CEO wish that steps had been taken in the past several years that may have avoided what is now largely inevitable. Considering the current situation, trading more than a decade of high capacity factor coal generation for a low capacity factor peaker unit has significant health and cost benefits that justify the tradeoff.

That said, avoiding the same scenario in 2035 should be a top priority. There are many risks associated with the Company's placeholder NGCC with CCS, even if it remains hypothetical at this time. The Commission should focus all parties on taking practical steps today that can increase the distribution and transmission system's ability to host more renewable energy and battery storage. This includes working with MISO on interconnection queue reform as well as with state stakeholders on the Company's distribution system planning process.

Q25. DOES THIS CONCLUDE YOUR TESTIMONY?

A25. Yes, it does.

KEVIN M. LUCAS

SOLAR ENERGY INDUSTRIES ASSOCIATION

Mr. Lucas is Senior Director of Utility Regulation and Policy for the Solar Energy Industries Association (SEIA). SEIA is the national trade association for the U.S. solar industry. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 30% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power.

Since 2010, Mr. Lucas has worked in the energy and environment industry focusing on renewable energy, energy efficiency, and greenhouse gas reduction. In his role at SEIA, Mr. Lucas develops expert witness testimony for rate cases, integrated resource plans, and other regulatory proceedings. He has also been actively involved in the ongoing New York Reforming the Energy Vision docket, focusing on distributed energy resource valuation and rate design. Prior to joining SEIA, Mr. Lucas worked for the Alliance to Save Energy, a Washington DC-based nonprofit focused on reducing energy use in the built environment. Before the Alliance, he worked for the Maryland Energy Administration, the state energy office, on numerous legislative and regulatory issues and developed and presented testimony before the Maryland General Assembly and the Maryland Public Service Commission.

Prior to entering the energy and environment field, Mr. Lucas was a manager at Accenture, a leading consulting firm. Mr. Lucas implemented enterprise resource planning software for Fortune 500 companies in industries such as consumer electronics, oil and gas, and manufacturing.

AREAS OF EXPERTISE

- Renewable Energy Policy Analysis: extensive experience analyzing renewable energy policy issues and communicating results to both expert and general audiences.
- Energy Efficiency Policy Analysis: detailed understanding of energy efficiency policies, including the development of potential studies and utility efficiency program design and implementation.
- Quantitative Analysis: deep expertise in quantitative analysis across a broad range of topics including analyzing financial and operational data sets, constructing models to explore electricity industry data, and incorporating original analysis into expert witness testimony.
- Energy Markets: studies interaction of renewable energy and energy efficiency policies with wholesale market operation and price impacts.
- Legislative Analysis: reviews legislation related to energy issues to discern potential impacts on markets, utilities, and customers.

EDUCATION

Mr. Lucas holds a Masters of Business Administration from the University of North Carolina, Kenan-Flagler Business School (2009) and a Bachelor of Science in Engineering, Mechanical Engineering from Princeton University (1998).

ACADEMIC HONORS

- Beta Gamma Sigma Honor Society
- Paul Fulton Fellowship, Kenan-Flagler Business School
- Graduated *cum laude* from Princeton University

EXPERT WITNESS TESTIMONY

Arizona Corporation Commission

- Docket No. E-01345A-19-0236 **-** *In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.*
    - Analyzing and modifying APS's class cost of service study, arguing for changes to time of use rate design, proposing new rate designs for solar plus storage installations, proposing improvements to non-residential rate designs, advocating for a "bring your own device" program.
- Docket No. E-01933a-22-0107 - *In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to its Operations Throughout the State of Arizona and for Related Approvals.*
    - Designed and proposed "Bring Your Own Device" program for behind-the-meter storage, redesigned rates intended to support residential and commercial behind-the-meter solar and storage, argued for stronger residential time of use rates.

Public Utilities Commission of the State of Colorado

- Proceeding 17A-0797E – *Public Service Company - Accelerated Depreciation - AD/RR*
    - Advocating for appropriate structure to utilize renewable energy funds to support the early retirement of coal facilities and to continue to support distributed resources
- Proceeding 19A-0369E – *In the Matter of The Application of Public Service Company of Colorado For Approval of Its 2020-2021 Renewable Energy Compliance Plan*
    - Advocating for changes to better support solar and solar plus storage installations
- Proceeding 19AL-0687E - *In the Matter of Advice No. 1814-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reflect a Modified Schedule RE-TOU and Related Tariff Changes to be Effective on Thirty-Days' Notice*
    - Designed and advocated for new data-based default time of use rate
- Proceeding No. 21A-0141E – *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan.*
    - Argued for changes to proposed resource plan to more accurately reflect capabilities of solar and storage, to updated template contracts, and improve procurement process
- Proceeding No. 21A-0625EG - *Public Service Company - Renewable Energy Compliance Plan.*
    - Advocated for various program modifications and enhancements for the utility's four-year distributed generation and community solar plan

Georgia Public Service Commission

- Docket No. 44160 – *In Re: Georgia Power Company's 2022 Integrated Resource Plan* and Docket No. 44161 – *In Re: Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Management Plan*
  - Advocated for improvements to proposed procurement plan with an increased focus on solar plus storage projects and distributed energy resources; recommended expansion of monthly netting program for BTM solar projects
- Docket No. 44280 – *Georgia Power 2022 Rate Case*
  - Analyzed and critiqued Georgia Power's rate case filing, specifically regarding its proposed flat interconnection fee for DG systems, its purported cost shift associated with BTM solar customers, its consistent and sizable excess revenue collection over a decade, and various proposals to modify or eliminate residential tariffs.

Maryland Public Service Commission

- Case 9153, 9154, 9155, 9156, 9157, 9362 - *In the Matter of Maryland Utility Efficiency, Conservation and Demand Response Programs Pursuant to the Empower Maryland Energy Efficiency Act of 2008*
  - Multiple filings regarding the design and implementation of Maryland's energy efficiency portfolio standard
- Case 9271 - *In re the Merger of Exelon Corp. & Constellation Energy Grp., Inc.*
  - Analysis of renewable energy commitments in merger proposal
- Case 9311 - *In re the Application of Potomac Elec. Power Co. for an Increase in its Retail Rates for the Distrib. of Elec. Energy*
  - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho
- Case 9326 - *In re the Application of Balt. Gas & Elec. Co. for Adjustments to its Elec. & Gas Base Rates.*
  - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho
- Case 9361 - *In re the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.*
  - Policy analysis of merger proposal

Michigan Public Service Commission

- Case U-18419 – *In the matter of the application of DTE ELECTRIC COMPANY for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*
  - Arguing against DTE Electric's proposal to construct a new natural gas combined cycle generating facility and instead meet its future capacity and energy needs with a distributed portfolio of solar, wind, energy efficiency, and demand response.
- Case U-20162 – *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*
  - Arguing against DTE Electric's proposal for a net energy metering successor tariff that improperly undervalued the contribution of distributed solar.
- Case U-20165 – *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*
  - Discussing Consumers Energy Company's integrated resource plan, arguing for advancing the deployment of solar to meet its capacity requirements, arguing against Consumers' proposed financial compensation mechanism for third-party PPA contracts, supporting a robust PURPA market, and supporting transparent and equitable competitive procurement guidelines.
- Case U-20471 – *In the matter of the Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.*
  - Evaluating DTE's integrated resource plan, arguing for the Company to modify its modeling assumptions for solar, analyzing the operation and reliability of DTE's aging peaker fleet, demonstrating that solar and solar plus storage could replace some of DTE's peakers, advocating for robust competition and third-party access to new resources.
- Case U-20836 – *In the matter of the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.*
  - Critiquing DTE's Stable Bill tariff as poorly designed and not reflective of costs; arguing against the requirement for solar customers to take service on the Stable Bill tariff; calculating a new cost-based outflow tariff for exported solar energy.
- Case U-21224 – *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.*
  - Critiquing Consumes Energy's proposed outflow compensation for DG customers, its minimum bill proposal, and supporting changes in its cost-of-service model.

Public Utility Commission of Nevada

- Docket Nos. 17-06003 & 17-06004 Phase III – Rate Design – *Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.*
    - Arguing against Nevada Power Company's proposal to increase fixed customer charge

North Carolina Utility Commission

- Docket E-100 Sub 165 – *2020 Integrated Resource Plans*
    - Advocating for modifications to Duke Energy's IRP, including assumptions on capital and O&M costs, operational assumptions, and natural gas forecast methodology

Public Service Commission of South Carolina

- Docket Nos. 2019-224-E and 2019-225-E – *South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC*
    - Advocating for modifications to Duke Energy's IRP, including assumptions on capital and O&M costs, operational assumptions, and natural gas forecast methodology

Public Utility Commission of Texas

- Docket 46831 – *Application of El Paso Electric Company to change rates*
    - Critiquing El Paso Electric's proposal to implement a three-part rate for residential and small commercial net metered customers

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Carbon Capture and Sequestration (CCS) in the United States

Updated October 5, 2022

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SUMMARY

Carbon Capture and Sequestration (CCS) in the United States

R44902

October 5, 2022

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Carbon capture and storage (or sequestration)—known as CCS—is a process intended to capture man-made carbon dioxide (CO_2) at its source and store it permanently underground. As one potential option for greenhouse gas mitigation, CCS could reduce the amount of CO_2—an important greenhouse gas—emitted to the atmosphere from power plants and other large industrial facilities. The concept of carbon utilization has also gained interest within Congress and in the private sector as a means for capturing CO_2 and converting it into potentially commercially viable products, such as chemicals, fuels, cements, and plastics, thereby reducing emissions to the atmosphere and helping offset the cost of CO_2 capture. CCS is sometimes referred to as CCUS—carbon capture, *utilization*, and storage. Direct air capture (DAC) is a related and emerging technology designed to remove atmospheric CO_2 directly.

The U.S. Department of Energy (DOE) has funded research and development (R&D) in aspects of CCS since at least 1997 within its Fossil Energy and Carbon Management Research, Development, Demonstration, and Deployment program (FECM) portfolio. Since FY2010, Congress has provided a total of $9.2 billion (in constant 2022 dollars) in annual appropriations for FECM, of which $2.7 billion (in constant 2022 dollars) was directed to CCS-related budget line items. The Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) provided $8.5 billion (nominal dollars) in supplemental funding for CCS for FY2022-FY2026, including funding for the construction of new carbon capture facilities, plus another $3.6 billion (nominal dollars) for DAC.

U.S. facilities capturing and injecting CO_2, and projects under development, operate in five industry sectors: chemical production, hydrogen production, fertilizer production, natural gas processing, and power generation. Most projects use the injected CO_2 to increase oil production from aging oil fields, known as enhanced oil recovery (EOR), while some facilities capture and inject CO_2 with the aim to sequester the CO2 in underground geologic formations. The Petra Nova project in Texas, starting operation in 2017, was the first and only U.S. fossil-fueled power plant generating electricity and capturing CO_2 in large quantities (over 1 million metric tons per year) until CCS operations were suspended in 2020.

The U.S. Environmental Protection Agency (EPA), under authorities to protect underground sources of drinking water, regulates CO_2 injection through its Underground Injection Control (UIC) program and associated regulations. While the agency establishes minimum standards and criteria for UIC programs, most states have the responsibility for regulating and permitting wells injecting CO_2 for EOR (classified as Class II recovery wells).

Congress has incentivized development of CCS projects through creation of the Internal Revenue Code Section 45Q tax credit for carbon sequestration, its use as a tertiary injectant for EOR, or other designated purposes. Recent Internal Revenue Service guidance and regulations on this tax credit are intended to provide increased certainty for industry by establishing processes and standards for "secure geologic storage of CO_2," among other requirements.

Several provisions in the Consolidated Appropriations Act, 2021 (P.L. 116-260) aim to further support CCS project development in the United States. The act revised and expanded DOE's ongoing CCS research, development, and demonstration activities, established expedited federal permitting eligibility for CO_2 pipelines (where applicable), and extended the start-of-construction deadline for facilities eligible for the Section 45Q tax credit, among other provisions. IIJA included additional supportive provisions. P.L. 117-169, commonly known as the Inflation Reduction Act of 2022, contained several provisions related to the 45Q tax credit that increase the amount of the tax credit for certain facilities and extend the deadline for start of construction, among other provisions.

There is broad agreement that costs for constructing and operating CCS would need to decrease before the technologies could be widely deployed. In the view of many proponents, greater CCS deployment is fundamental to reduce CO_2 emissions (or reduce the concentration of CO_2 in the atmosphere, in the case of DAC) and to help mitigate human-induced climate change. In contrast, some stakeholders do not support CCS as a mitigation option, citing concerns with continued fossil fuel combustion and the uncertainties of long-term underground CO_2 storage.

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Carbon capture and storage (or sequestration)—known as CCS—is a process intended to capture man-made carbon dioxide (CO_2) at its source and store it to avoid its release to the atmosphere. CCS is sometimes referred to as CCUS—carbon capture, *utilization*, and storage. CCS could reduce the amount of CO_2 emitted to the atmosphere from power plants and other large industrial facilities. An integrated CCS system would include three main steps: (1) capturing and separating CO_2 from other gases; (2) transporting the captured and compressed CO_2 to the storage or sequestration site; and (3) injecting the CO_2 in underground geological reservoirs (the process is explained more fully below in "CCS Primer"). The *utilization* part of CCUS has been of increased interest to researchers and policymakers. *Utilization* refers to the beneficial use of CO_2—in lieu of storing it—as a means of mitigating CO_2 emissions and converting it to chemicals, cements, plastics, and other products.[1] This report uses the term *CCS* except in cases where utilization is specifically discussed.

The U.S. Department of Energy (DOE) has long supported research and development (R&D) on CCS, currently within its Fossil Energy and Carbon Management Research, Development, Demonstration, and Deployment program (FECM).[2] From FY2010 to FY2022, Congress provided a total of $9.2 billion (2022 dollars)[3] in annual appropriations for FECM, of which $2.7 billion (2022 dollars) was directed to CCS-related budget line items. Additionally, Congress provided a supplemental appropriation of $3.4 billion ($4.4 billion in 2022 dollars) for CCS in the American Recovery and Reinvestment Act of 2009 (ARRA; P.L. 111-5). It provided another supplemental appropriation of $8.5 billion (nominal dollars) for CCS in the Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) for FY2022 to FY2026.[4] Congress has expressed support for continuing federal investment in CCS research and development—including financial support for demonstration projects—through the appropriations process in recent years and in DOE research reauthorizations provided in the Energy Act of 2020 (Division Z of the Consolidated Appropriations Act, 2021; P.L. 116-260). The IIJA provided funding for several programs authorized by the Energy Act of 2020 and established other programs aimed to promote CCS in the United States, as discussed later in this report.

Congress has also enacted tax credits for facilities that capture and sequester CO_2—one strategy for incentivizing CCS project deployment. In 2022, Congress enacted as part of P.L. 117-260, commonly known as the Inflation Reduction Act of 2022 (IRA), provisions that increased the tax credit for sequestering or utilizing CO_2, referred to as the "Section 45Q" tax credit.[5] The IRA also extended the deadline for start of construction of certain facilities seeking the tax credit. The Internal Revenue Service regulations on Section 45Q issued in early 2021 could provide a more stable investment environment for project planning.

Congressional interest in addressing climate change has also increased interest in CCS, though debate continues as to what role, if any, CCS should play in greenhouse gas emissions reductions. While some policymakers and other stakeholders support CCS as one option for mitigating CO_2 emissions, others raise concerns that CCS may encourage continued fossil fuel use and that CO_2

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[1] See, for example, U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL), *Carbon Utilization Program*, at https://www.netl.doe.gov/coal/carbon-utilization.

[2] Formerly called Fossil Energy Research and Development.

[3] Throughout this report, nominal dollars are converted to Q2 2022 dollars (referred to in this report as 2022 dollars) using the price index for federal government investment in research and development from Bureau of Economic Analysis, "National Income and Product Accounts," Table 3.9.4.

[4] For more information, see CRS Report R47034, *Energy and Minerals Provisions in the Infrastructure Investment and Jobs Act (P.L. 117-58)*, coordinated by Brent D. Yacobucci.

[5] The credit is codified at 26 U.S.C. §45Q.

could leak from underground reservoirs into the air or other reservoirs, thereby negating climate benefits of CCS.[6]

This report includes a primer on the CCS (and carbon utilization) process; overviews of the DOE program for CCS R&D, U.S. Environmental Protection Agency (EPA) regulation of underground CO_2 injection used for CCS, and the Section 45Q tax credit for CO_2 sequestration; and a discussion of CCS policy issues for Congress. An evaluation of the fate of injected underground CO_2 and the permanence of CO_2 storage is beyond the scope of this report.

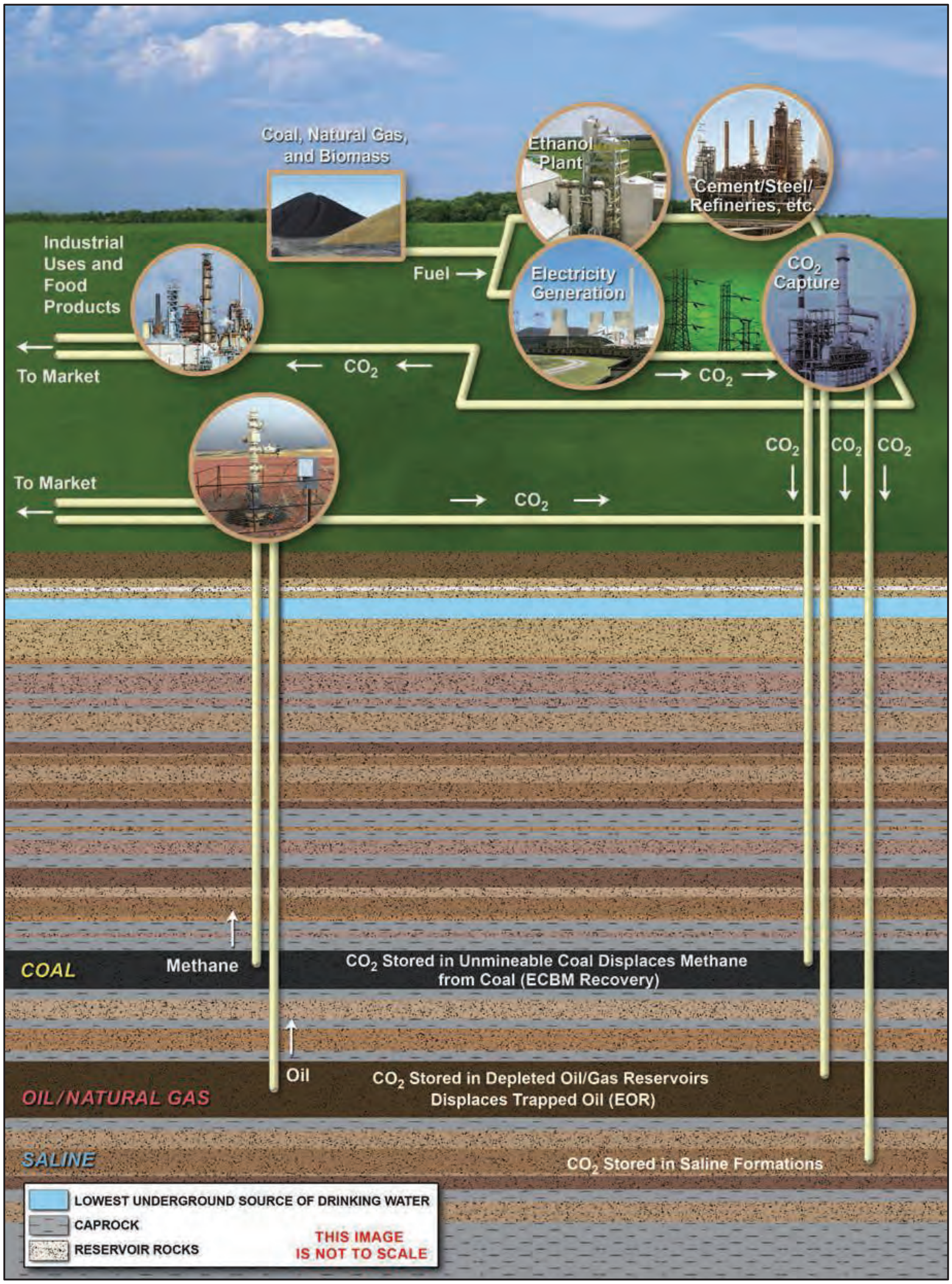
CCS Primer

An integrated CCS system includes three main steps: (1) capturing and separating CO_2 from other gases; (2) compressing and transporting the captured CO_2 to the sequestration site; and (3) injecting the CO_2 in subsurface geological reservoirs. The most technologically challenging and costly step in the process is the first step, carbon capture. Carbon capture equipment is capital-intensive to build and energy-intensive to operate. Power plants can supply their own energy to operate CCS equipment, but the amount of energy a power plant uses to capture and compress CO_2 is that much less electricity the plant can sell to its customers. This difference, sometimes referred to as the *energy penalty* or the *parasitic load*, has been reported to be around 20% of a power plant's capacity.[7] **Figure 1** shows the options for parts of an integrated CCS process schematically from source to storage.

[6] For example, the International Energy Agency (IEA) includes CCS as a "key solution" in its 2021 report on achieving global net zero greenhouse gas emissions. IEA anticipates widespread CCS deployment in several industries (e.g., power, cement, and hydrogen production) as well as direct air capture. International Energy Agency (IEA), *Net Zero by 2050: A Roadmap for the Global Energy Sector*, May 2021. See also the White House Environmental Justice Advisory Council, *Climate and Economic Justice Screening Tool and Justice 40 Interim Final Recommendations*, May 13, 2021, p. 58; and Richard Conniff, "Why Green Groups Are Split on Subsidizing Carbon Capture Technology," *YaleEnvironment360*, April 9, 2018.

[7] See, for example, Howard J. Herzog, Edward S. Rubin, and Gary T. Rochelle, "Comment on 'Reassessing the Efficiency Penalty from Carbon Capture in Coal-Fired Power Plants,'" *Environmental Science and Technology*, vol. 50 (May 12, 2016), pp. 6112-6113.

Figure 1. Options for an Integrated CCS Process: Capture, Injection, and Utilization



Source: U.S. Department of Energy, Office of Fossil Energy, "Carbon Utilization and Storage Atlas," Fourth Edition, 2012, p. 4.

Notes: *EOR* is enhanced oil recovery; *ECBM* is enhanced coal bed methane recovery. *Caprock* refers to a relatively impermeable formation. Terms are explained in "CO2 Injection and Sequestration."

The transport and injection/storage steps of the CCS process are not technologically challenging per se, as compared to the capture step. Carbon dioxide pipelines are used for enhanced oil recovery (EOR) in regions of the United States today, and for decades large quantities of fluids have been injected into the deep subsurface for a variety of purposes, such as disposal of wastewater from oil and gas operations or of municipal wastewater.[8] However, the transport and storage steps still face challenges, including economic and regulatory issues, rights-of-way, questions regarding the permanence of CO_2 sequestration in deep geological reservoirs, and ownership and liability issues for the stored CO_2, among others.

CO_2 Capture

The first step in CCS is to capture CO_2 at the source and separate it from other gases.[9] As noted above, this is typically the most costly part of a CCS project, representing up to 75% of project costs in some cases.[10] Current carbon capture costs are estimated at $43-$65 per ton CO_2 captured, though cost reductions of 50%-70% may be possible as the industry matures.[11]

Currently, three main approaches are available to capture CO_2 from large-scale industrial facilities or power plants: (1) postcombustion capture; (2) precombustion capture; and (3) oxy-fuel combustion capture.

The following sections summarize each of these approaches. A detailed description and assessment of the carbon capture technologies is provided in CRS Report R41325, *Carbon Capture: A Technology Assessment*, by Peter Folger.

Postcombustion Capture

The process of postcombustion capture involves extracting CO_2 from the flue gas—the mix of gases produced that goes up the exhaust stack—following combustion of fossil fuels or biomass. Several commercially available technologies, some involving absorption using chemical solvents (such as an *amine*; see **Figure 2**), can in principle be used to capture large quantities of CO_2 from flue gases.[12] In a vessel called an *absorber*, the flue gas is "scrubbed" with an amine solution, typically capturing 85% to 90% of the CO_2. The CO_2-laden solvent is then pumped to a second vessel, called a *regenerator*, where heat is applied (in the form of steam) to release the CO_2. The resulting stream of concentrated CO_2 is then compressed and piped to a storage site, while the depleted solvent is recycled back to the absorber.

Other than the 2017-2020 Petra Nova project (discussed below in "Petra Nova: The First Large U.S. Power Plant with CCS"), no large U.S. commercial electricity-generating plant has been equipped with carbon capture equipment, though several projects are under development.

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[8] Injecting CO_2 into an oil reservoir often increases or enhances production by lowering the viscosity of the oil, which allows it to be pumped more easily from the formation. The process is sometimes referred to as *tertiary recovery* or *enhanced oil recovery* (EOR). EOR may involve incidental carbon storage.

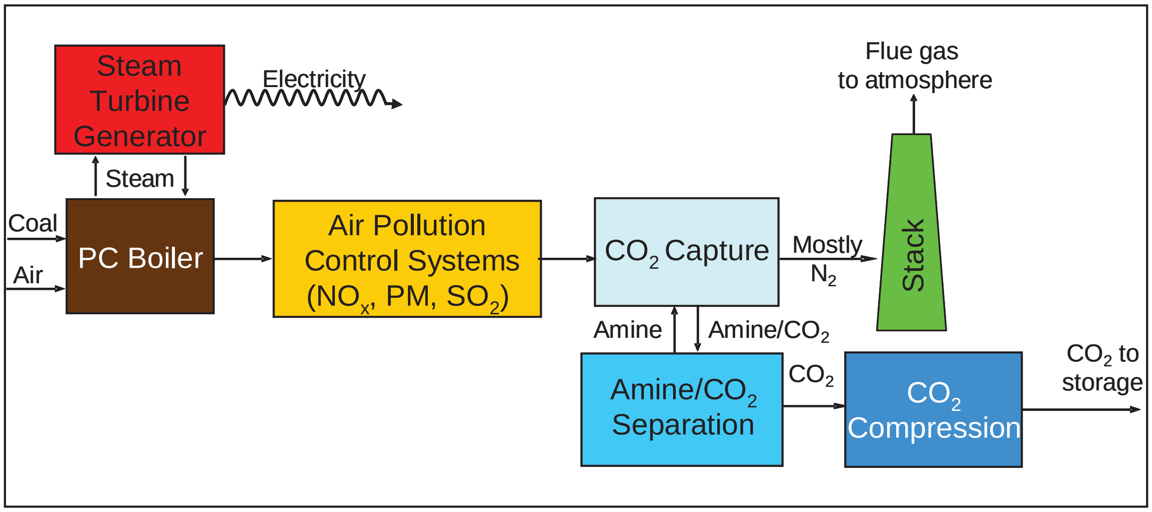
[9] Carbon capture is related to, but distinct from, direct air capture (DAC), a process that captures CO_2 from the atmosphere. DAC is discussed in more detail in later sections of this report. For a comparison of CCS and DAC, see CRS In Focus IF11501, *Carbon Capture Versus Direct Air Capture*, by Ashley J. Lawson.

[10] National Petroleum Council (NPC), *Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage, Chapter 5*, July 17, 2020.

[11] Greg Kelsall, *Carbon Capture Utilisation and Storage - Status, Barriers, and Potential*, International Energy Agency (IEA) Clean Coal Centre, July 2020.

[12] *Amines* are a family of organic solvents, which can "scrub" the CO_2 from the flue gas. When the CO_2-laden amine is heated, the CO_2 is released to be compressed and stored, and the depleted solvent is recycled.

Figure 2. Diagram of Postcombustion CO_2 Capture in a Coal-Fired Power Plant Using an Amine Scrubber System



Source: E. S. Rubin, "CO_2 Capture and Transport," *Elements*, vol. 4 (2008), pp. 311-317.

Notes: Other major air pollutants (nitrogen oxides-NO_x, particulate matter-PM, and sulfur dioxide-SO_2) are removed from the flue gas prior to CO_2 capture. PC = pulverized coal. N_2 = nitrogen gas.

Precombustion Capture (Gasification)

The process of precombustion capture separates CO_2 from the fuel by combining the fuel with air and/or steam to produce hydrogen for combustion and a separate CO_2 stream that could be stored. For coal-fueled power plants, this is accomplished by reacting coal with steam and oxygen at high temperature and pressure, a process called *partial oxidation*, or *gasification* (**Figure 3**).[13] The result is a gaseous fuel consisting mainly of carbon monoxide and hydrogen—a mixture known as *synthesis gas*, or *syngas*—which can be burned to generate electricity. After particulate impurities are removed from the syngas, a two-stage *shift reactor* converts the carbon monoxide to CO_2 via a reaction with steam (H_2O). The result is a mixture of CO_2 and hydrogen. A chemical solvent, such as the widely used commercial product Selexol (which employs a glycol-based solvent), then captures the CO_2, leaving a stream of nearly pure hydrogen. This is burned in a combined cycle power plant to generate electricity—known as an *integrated gasification combined-cycle plant* (IGCC)—as depicted in **Figure 3**. Existing IGCC power plants in the United States do not capture CO_2.[14]

One example of IGCC technology in operation today is the Polk Power Station about 40 miles southeast of Tampa, FL.[15] The 250 megawatt (MW) unit generates electricity from coal-derived syngas produced and purified onsite. The Polk Power Station does not capture CO_2.

An example of precombustion capture technology, though not for power generation, is the Great Plains Synfuels Plant in Beulah, ND. The Great Plains plant produces synthetic natural gas from

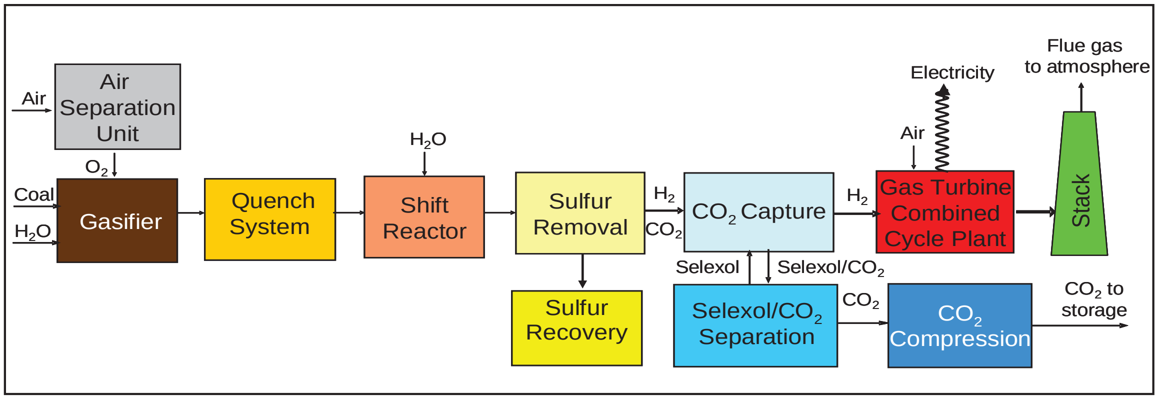
13 See CRS Report R41325, *Carbon Capture: A Technology Assessment*, by Peter Folger.

14 One integrated gasification combined-cycle project in Edwardsport, IN, was designed with sufficient space to add carbon capture in the future. For further discussion, see DOE, NETL, "IGCC Project Examples," at https://netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/project-examples.

15 For more information about the Polk Power Station, see DOE, NETL, "Tampa Electric Integrated Gasification Combined-Cycle Project," at https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/tampa.

lignite coal through a gasification process, and the natural gas is shipped out of the facility for sale in the natural gas market. The process also produces a stream of high-purity CO_2, which is piped northward into Canada for use in EOR at the Weyburn oil field.[16]

Figure 3. Diagram of Precombustion CO_2 Capture from an IGCC Power Plant



Source: E. S. Rubin, "CO2 Capture and Transport," *Elements*, vol. 4 (2008), pp. 311-317.

Oxy-Fuel Combustion Capture

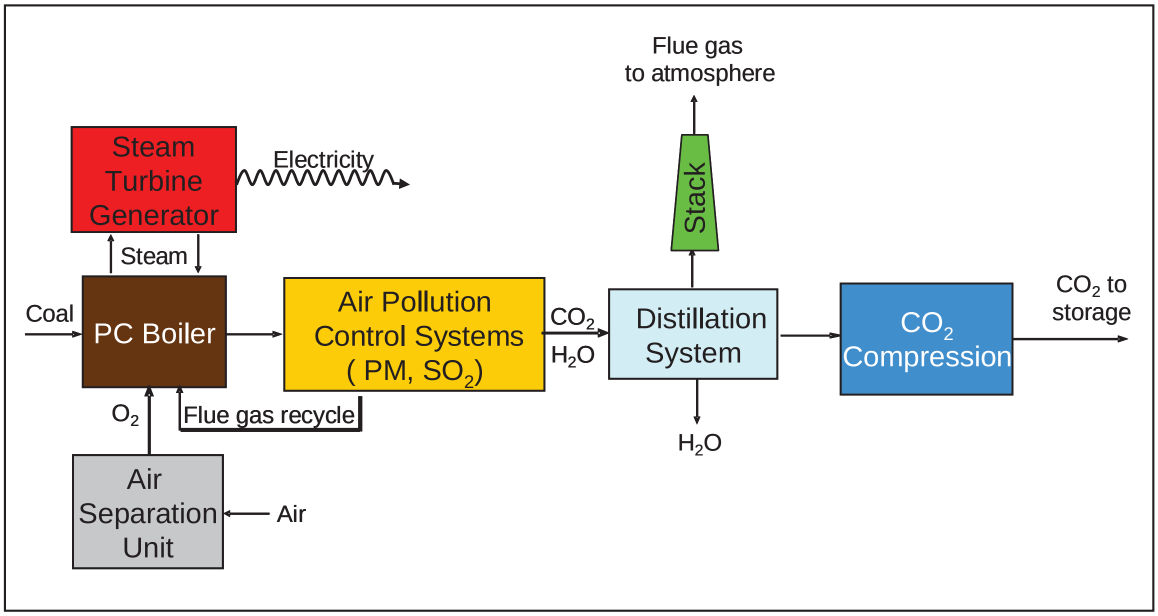
The process of oxy-fuel combustion capture uses pure oxygen instead of air for combustion and produces a flue gas that is mostly CO_2 and water, which are easily separable, after which the CO_2 can be compressed, transported, and stored (**Figure 4**). Oxy-fuel combustion requires an oxygen production step, which would likely involve a cryogenic process (shown as the air separation unit in **Figure 4**). The advantage of using pure oxygen is that it eliminates the large amount of nitrogen in the flue gas stream, thus reducing the formation of smog-forming pollutants like nitrogen oxides.

Currently oxy-fuel combustion projects are at the lab- or bench-scale, ranging up to verification testing at a pilot scale.[17]

[16] For a more detailed description of the Great Plains Synfuels plant, see DOE, NETL, "SNG from Coal: Process & Commercialization," at https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/great-plains.

[17] For more information, see NETL, *Oxy-Combustion*, at https://netl.doe.gov/node/7477.

Figure 4. Diagram of Oxy-Combustion CO_2 Capture from a Coal-Fired Power Plant



Source: E. S. Rubin, "CO_2 Capture and Transport," *Elements*, vol. 4 (2008), pp. 311-317.

Allam Cycle

The Allam Cycle is a novel power plant design that uses supercritical CO_2 (sCO_2) to drive an electricity-generating turbine.[18] sCO_2 is CO_2 held at certain temperature and pressure conditions, giving it unique chemical and physical properties.[19] In contrast, most power plants in operation today (and most proposed power plants using CCS) use steam (i.e., water) to drive a turbine. Power plants using the Allam Cycle combust fossil fuels in pure oxygen, producing CO_2 and water.[20] The CO_2 can be reused multiple times to generate electricity, or piped away for utilization or storage. The excess CO_2 produced by the cycle is sufficiently pure to be directly transported or used without requiring an additional capture or purification step. For power plant operations, sCO_2 may be more efficient than steam. Initial estimates indicate that power plants using the Allam Cycle could have comparable efficiencies to natural gas combined cycle power plants without CCS.[21]

[18] NET Power, *The Allam-Fetvedt Cycle*, at https://netpower.com/the-cycle/.

[19] *Supercritical CO_2* refers to temperature and pressure conditions above a critical point where CO_2 has characteristics of both a gas and a liquid. In this "supercritical" state, small changes in temperature or pressure can result in large changes in density, which can make supercritical CO_2 a useful working fluid for power generation. The *critical point for CO_2* refers to the temperature and pressure conditions above which matter phase boundaries disappear.

[20] The operational NET Power facility uses natural gas as a fuel, but coal may also be used. One of the NET Power project developers, 8 Rivers Capital, received a DOE grant in 2019 to study the design of a coal-fired power plant using the Allam Cycle. DOE, "U.S. Department of Energy Invests $7 Million for Projects to Advance Coal Power Generation Under Coal FIRST Initiative," at https://netl.doe.gov/node/9282.

[21] Rodney Allam et al., "Demonstration of the Allam Cycle: An update on the development status of a high efficiency supercritical carbon dioxide power process employing full carbon capture," *Energy Procedia*, vol. 114 (2017), pp. 5948-5966.

The NET Power demonstration facility in La Porte, TX, is the first power plant to use the Allam Cycle. Plans for two commercial-scale Allam Cycle power plants—one in Colorado and one in Illinois—were announced in April 2021.[22]

CO_2 Transport

After the CO_2 capture step, the gas is purified and compressed (typically into a supercritical state) to produce a concentrated stream for transport. Pipelines are the most common method for transporting CO_2 in the United States. Approximately 5,000 miles of pipelines transport CO_2 in the United States, predominantly to oil fields, where it is used for EOR.[23] Transporting CO_2 in pipelines is similar to transporting fuels such as natural gas and oil; it requires attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas.

Costs for pipeline construction vary, depending upon length and capacity; right-of-way costs; whether the pipeline is onshore or offshore; whether the route crosses mountains, large rivers, or frozen ground; and other factors. The quantity and distance transported will mostly determine shipping costs. Shipping rates for CO_2 pipelines in the United States may be negotiated between the operator and shippers, or may be subject to rate regulation if they are considered open access pipelines with eminent domain authority. Siting of CO_2 pipelines is under the jurisdiction of the states, although the federal government regulates their safety.[24]

Even though regional CO_2 pipeline networks currently operate in the United States for EOR, developing a more expansive network for CCS could pose regulatory and economic challenges. Some studies have suggested that development of a national CO_2 pipeline network that would address the broader issue of greenhouse gas emissions reduction using CCS may require a concerted federal policy, in some cases including federal incentives for CO_2 pipeline development.[25] In 2020, enacted legislation included provisions to facilitate the study and development of CO_2 pipelines that could be used for CCS.[26]

Using marine vessels also may be feasible for transporting CO_2 over large distances or overseas. Liquefied natural gas and liquefied petroleum gases (i.e., propane and butane) are routinely shipped by marine tankers on a large scale worldwide.[27] Marine tankers transport CO_2 today, but at a small scale because of limited demand. Marine tanker costs for CO_2 shipping are uncertain, because no large-scale CO_2 transport system via vessel (in millions of metric tons of CO_2 per year, for example) is operating, although such an operation has been proposed in Europe.[28]

[22] Akshat Rathi, "U.S. Startup Plans to Build First Zero-Emission Gas Power Plants," *Bloomberg Green*, April 15, 2021.

[23] Pipeline and Hazardous Materials Safety Administration, "Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems," web page, July 1, 2020, at https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-hazardous-liquid-or-carbon-dioxide-systems.

[24] For additional information on CO_2 pipeline safety, see CRS Insight IN11944, *Carbon Dioxide Pipelines: Safety Issues*, by Paul W. Parfomak.

[25] See, for example, Elizabeth Abramson et al., "Transport Infrastructure for Carbon Capture and Storage," Regional Carbon Capture Deployment Initiative, June 2020; Ryan W. J. Edwards and Michael A. Celia, "Infrastructure to Enable Deployment of Carbon Capture, Utilization, and Storage in the United States," *Proceedings of the National Academy of Sciences*, September 18, 2018.

[26] USE IT Act (H.R. 1166 and S. 383), 116th Congress, and enacted as part of P.L. 116-260.

[27] Rail cars and trucks also can transport CO_2, but this mode probably would be uneconomical for large-scale CCS operations.

[28] See IEA, "Northern Lights."

CO_2 Injection and Sequestration

Three main types of geological formations are being considered for underground CO_2 injection and sequestration: (1) depleted oil and gas reservoirs, (2) deep saline reservoirs, and (3) unmineable coal seams. In each case, CO_2 in a supercritical state would be injected into a porous rock formation below ground that holds or previously held fluids (**Figure 1**). When CO_2 is injected at depths greater than about half a mile (800 meters) in a typical reservoir, the pressure keeps the injected CO_2 supercritical, making the CO_2 less likely to migrate out of the geological formation. The process also requires that the geological formation have an overlying *caprock* or relatively impermeable formation, such as shale, so that injected CO_2 remains trapped underground (**Figure 1**). Injecting CO_2 into deep geological formations uses existing technologies that have been primarily developed and used by the oil and gas industry and that potentially could be adapted for long-term storage and monitoring of CO_2.

The storage capacity for CO_2 when considering all the sedimentary basins in the world is potentially very large compared to total CO_2 emissions from stationary sources.[29] In the United States alone, DOE has estimated the total storage capacity to range between about 2.6 trillion and 22 trillion metric tons of CO_2 (see **Table 1**).[30] The suitability of any particular site, however, depends on many factors, including proximity to CO_2 sources and other reservoir-specific qualities such as porosity, permeability, and potential for leakage.[31] For CCS to succeed in mitigating atmospheric emissions of CO_2, it is assumed that each reservoir type would permanently store the vast majority of injected CO_2, keeping the gas isolated from the atmosphere in perpetuity. That assumption is untested, although part of the DOE CCS R&D program has been devoted to experimenting and modeling the behavior of large quantities of injected CO_2. Theoretically—and without consideration of costs, regulatory issues, public acceptance, infrastructure needs, liability, ownership, and other issues—the United States could store its total CO_2 emissions from the electricity generating sector and other large stationary sources (at the current rate of emissions) for centuries.

Table 1. Estimates of the U.S. Storage Capacity for CO_2

(in billions of metric tons)

	Low	Medium	High
Oil and Natural Gas Reservoirs	186	205	232
Unmineable Coal	54	80	113
Saline Formations	2,379	8,328	21,633
Total	**2,618**	**8,613**	**21,978**

Source: U.S. Department of Energy, National Energy Technology Laboratory, *Carbon Storage Atlas*, 5th ed., August 20, 2015, at https://www.netl.doe.gov/File%20Library/Research/Coal/carbon-storage/atlasv/ATLAS-V-2015.pdf.

[29] *Sedimentary basins* refer to natural large-scale depressions in the Earth's surface that are filled with sediments and fluids and are therefore potential reservoirs for CO_2 storage.

[30] For comparison, in 2020 the United States emitted 1.4 billion metric tons of CO_2 from the electricity generating sector. See U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2020*, Table 2-4, at https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2020.

[31] *Porosity* refers to the amount of open space in a geologic formation—the openings between the individual mineral grains or rock fragments. *Permeability* refers to the interconnectedness of the open spaces, or the ability of fluids to migrate through the formation. *Leakage* means that the injected CO_2 can migrate up and out of the intended reservoir, instead of staying trapped beneath a layer of relatively impermeable material, such as shale.

Notes: Data current as of November 2014. The estimates represent only the physical restraints on storage (i.e., the pore volume in suitable sedimentary rocks) and do not consider economic or regulatory constraints. The low, medium, and high estimates correspond to a calculated probability of exceedance of 90%, 50%, and 10%, respectively, meaning that there is a 90% probability that the estimated storage volume will exceed the low estimate and a 10% probability that the estimated storage volume will exceed the high estimate. Numbers in the table may not add precisely due to rounding.

Oil and Gas Reservoirs

Pumping water, gas, or chemical injectants into oil and gas reservoirs to boost production (that is, EOR) has been practiced in the oil and gas industry for several decades. CO_2 is one type of injectant that is used in EOR processes. The United States is a world leader in this technology, and oil and gas operators inject approximately 68 million tons of CO_2 underground each year to help recover oil and gas resources.[32] Most of the CO_2 used for EOR in the United States comes from naturally occurring geologic formations, however, not from industrial sources. Using CO_2 from industrial emitters has appeal because the costs of capture and transport from the facility could be partially offset by revenues from oil and gas production. The majority of existing CCS facilities offset some of the costs by selling the captured CO_2 for EOR. According to some studies, EOR using CO_2 captured from an industrial source could potentially produce crude oil with a lower lifecycle greenhouse gas emissions intensity than either oil produced without EOR or oil produced through EOR using naturally occurring CO_2, depending on the process characteristics and analysis methodologies used.[33] CO_2 can be used for EOR onshore or offshore. To date, most U.S. CO_2 projects associated with EOR are onshore, with the bulk of activities in western Texas.[34] Carbon dioxide also can be injected into oil and gas reservoirs that are completely depleted, which would serve the purpose of long-term sequestration but without any offsetting financial benefit from oil and gas production.

Deep Saline Reservoirs

Some rocks in sedimentary basins contain saline fluids—brines or brackish water unsuitable for agriculture or drinking. As with oil and gas, deep saline reservoirs can be found onshore and offshore; they are often part of oil and gas reservoirs and share many characteristics. The oil industry routinely injects brines recovered during oil production into saline reservoirs for disposal.[35] As **Table 1** shows, deep saline reservoirs constitute the largest potential for storing CO_2 by far. However, unlike oil and gas reservoirs, storing CO_2 in deep saline reservoirs does not have the potential to enhance the production of oil and gas or to offset costs of CCS with revenues from the produced oil and gas.

[32] As of 2014. See Vello Kuuskraa and Matt Wallace, "CO2-EOR Set for Growth as New CO2 Supplies Emerge," *Oil and Gas Journal*, vol. 112, no. 4 (April 7, 2014), p. 66. Hereinafter Kuuskraa and Wallace, 2014.

[33] For example, one study comparing lifecycle greenhouse gas emissions of EOR using different sources of CO_2 found that using CO_2 captured from an IGCC power plant or a natural gas combined cycle power plant resulted in oil with 25%-60% lower lifecycle greenhouse gas emissions. CO_2 source is not the only determinant of the net emissions reductions associated with EOR. The types of EOR technology and methods also affect estimated emissions reductions in scientific studies. To a certain extent, EOR can be optimized for CO_2 storage (i.e., conducted in such a way as to attempt to maximize the storage of CO_2 as opposed to maximizing the production of oil).

[34] As of 2014, nearly two-thirds of oil production using CO_2 for EOR came from the Permian Basin, located in western Texas and southeastern New Mexico. Kruskaa and Wallace, 2014, p. 67.

[35] The U.S. Environmental Protection Agency (EPA) regulates this practice under authority of the Safe Drinking Water Act, Underground Injection Control (UIC) program. See the EPA UIC program at https://www.epa.gov/uic/class-ii-oil-and-gas-related-injection-wells.

Unmineable Coal Seams

U.S. coal resources that are not mineable with current technology are those in which the coal beds are not thick enough, are too deep, or lack structural integrity adequate for mining.[36] Even if they cannot be mined, coal beds are commonly permeable and can trap gases, such as methane, which can be extracted (a resource known as *coal-bed methane*, or CBM). Methane and other gases are physically bound (adsorbed) to the coal. Studies indicate that CO_2 binds to coal even more tightly than methane binds to coal.[37] CO_2 injected into permeable coal seams could displace methane, which could be recovered by wells and brought to the surface, providing a source of revenue to offset the costs of CO_2 injection. Unlike EOR, injecting CO_2 and displacing, capturing, and selling CBM (a process known as *enhanced coal bed methane recovery*, or ECBM) to offset the costs of CCS is not part of commercial production. Currently, nearly all CBM is produced by removing water trapped in the coal seam, which reduces the pressure and enables the release of the methane gas from the coal.

Carbon Utilization

The concept of carbon utilization has gained increasingly widespread interest within Congress and in the private sector as a means for capturing CO_2 and storing it in potentially useful and commercially viable products, thereby reducing emissions to the atmosphere and offsetting the cost of CO_2 capture. EOR is currently the main use of captured CO_2, and some observers envision EOR will continue to dominate carbon utilization for some time, supporting the scale-up of capture technologies that could later rely upon other utilization pathways.[38] Nonetheless, research activities and congressional interest in utilization tend to focus on uses other than EOR. For example, P.L. 115-123, the Bipartisan Budget Act of 2018, which expanded the Section 45Q tax credit for carbon capture and sequestration, excludes EOR from the definition of carbon utilization. P.L. 115-123 defines carbon utilization as[39]

- the fixation of such qualified carbon oxide through photosynthesis or chemosynthesis, such as through the growing of algae or bacteria;
- the chemical conversion of such qualified carbon oxide to a material or chemical compound in which such qualified carbon oxide is securely stored; and
- the use of such qualified carbon oxide for any other purpose for which a commercial market exists (with the exception of use as a tertiary injectant in a qualified enhanced oil or natural gas recovery project), as determined by the Secretary [of the Treasury].[40]

P.L. 116-260 provides two authorizations for a DOE carbon utilization research program (to be coordinated as a single program) in the USE IT Act and Energy Act of 2020. Both focus on

[36] *Coal bed* and *coal seam* are interchangeable terms.

[37] IPCC Special Report, p. 217.

[38] For example, "For good reasons, many seek to find ways to use CO_2 to create economic value in a climate-positive way. Today, the primary use of CO_2 is for enhanced oil recovery. This is an important near-term pathway and provides opportunities to finance projects, scale-up technologies and reduce costs." Written testimony of Dr. S. Julio Friedmann, U.S. Congress, Senate Committee on Energy and Natural Resources, *Full Committee Hearing to Examine Development and Deployment of Large-Scale Carbon Dioxide Management Technologies*, 116th Cong., 2nd sess., July 28, 2020.

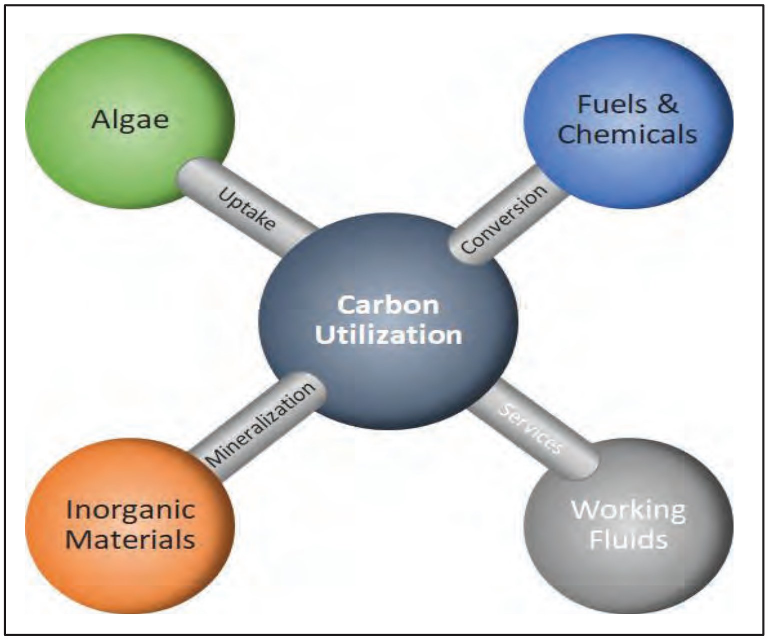
[39] CRS In Focus IF11455, *The Tax Credit for Carbon Sequestration (Section 45Q)*, by Angela C. Jones and Molly F. Sherlock.

[40] P.L. 115-123, §41119. A *tertiary injectant* refers to the use of CO_2 for EOR or enhanced natural gas recovery.

"novel uses" for carbon and CO_2, such as "chemicals, plastics, building materials, fuels, cement, products of coal utilization in power systems or in other applications, and other products with demonstrated market value."[41]

Figure 5 illustrates an array of potential utilization pathways: uptake using algae (for biomass production), conversion to fuels and chemicals, mineralization into inorganic materials, and use as a working fluid (e.g., for EOR) or other services.

Figure 5. Schematic Illustration of Current and Potential Uses of CO_2



Source: U.S. DOE, National Energy Technology Laboratory (NETL), at https://www.netl.doe.gov/coal/carbon-utilization.

[41] P.L. 116-260, Division S, §102(c).

Direct Air Capture

Direct air capture (DAC) is an emerging set of technologies that aim to remove CO_2 directly from the atmosphere, as opposed to the point source capture of CO_2 from a source like a power plant (as described above in "CO2 Capture").[42]

DAC systems typically employ a chemical capture system to separate CO_2 from ambient air, add energy to separate the captured CO_2 from the chemical substrate, and remove the purified CO_2 to be stored permanently or utilized for other purposes.[43] This process is similar to postcombustion carbon capture in some ways, though DAC and CCS differ in a number of ways.

DAC systems have the potential to be classified as net carbon negative, meaning that if the captured CO_2 is permanently sequestered or becomes part of long-lasting products such as cement or plastics, the end result would be a reduction in the atmospheric concentration of CO_2. In addition, DAC systems can be sited almost anywhere—they do not need to be near power plants or other point sources of CO_2 emissions. They could be located, for example, close to manufacturing plants that require CO_2 as an input, and would not necessarily need long pipeline systems to transport the captured CO_2.

The concentration of CO_2 in ambient air is far lower than the concentration found at most point sources. Thus, a recognized drawback of DAC systems is their high cost per ton of CO_2 captured, compared to the more conventional CCS technologies.[44] A 2011 assessment estimated costs at roughly $600 per ton of captured CO_2.[45] A more recent assessment from one of the companies developing DAC technology, however, projects lower costs for commercially deployed plants of between $94 and $232 per ton.[46] In 2021, DOE launched a research effort called the Carbon Negative Shot, aiming to achieve CO_2 removal (including DAC) for less than $100 per ton.[47] By comparison, some estimate costs for conventional CCS from coal-fired electricity generating plants in the United States between $48 and $109 per ton.[48]

Congress has sometimes combined support for CCS and DAC into single proposals, despite the differences in the technologies. For example, the federal tax credit for carbon sequestration applies to CCS and DAC projects (with CO_2 injection for sequestration).[49] In other cases, though, Congress has treated the technologies separately. For example, the Energy Act of 2020 provided CCS R&D authorizations primarily in Title IV—Carbon Management, while most DAC R&D authorizations are in Title V—Carbon Removal.

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[42] CRS In Focus IF11501, *Carbon Capture Versus Direct Air Capture*, by Ashley J. Lawson. Some processes capture CO_2 from seawater instead of the atmosphere. These are sometimes called *direct ocean capture*, or *DOC*.

[43] For a detailed assessment of DAC technology, see the American Physical Society, *Direct Air Capture of CO_2 with Chemicals: A Technology Assessment for the APS Panel on Public Affairs*, June 1, 2011, at https://www.aps.org/policy/reports/assessments/upload/dac2011.pdf. Hereinafter American Physical Society, 2011. Additional background information is also available in National Academies of Sciences, Engineering, and Medicine, *Negative Emissions Technologies and Reliable Sequestration: A Research Agenda*, 2019.

[44] Generally, the more dilute the concentration of CO_2, the higher the cost to extract it, because much larger volumes are required to be processed. By comparison, the concentration of CO_2 in the atmosphere is about 0.04%, whereas the concentration of CO_2 in the flue gas of a typical coal-fired power plant is about 14%. Duncan Leeson, Andrea Ramirez, and Niall Mac Dowell, "Carbon Capture and Storage from Industrial Sources," in *Carbon Capture and Storage*, ed. Mai Bui and Niall Mac Dowell, p. 299.

[45] American Physical Society, 2011, p. 13.

[46] Robert F. Service, "Cost Plunges for Capturing Carbon Dioxide from the Air," *Science*, June 7, 2018, at http://www.sciencemag.org/news/2018/06/cost-plunges-capturing-carbon-dioxide-air.

[47] DOE, "Secretary Granholm Launches Carbon Negative Earthshots to Remove Gigatons of Carbon Pollution From the Air by 2050," press release, November 5, 2021.

[48] Lawrence Irlam, *The Costs of CCS and Other Low-Carbon Technologies in the United States-2015 Update*, Global CCS Institute, July 2015, p. 1, at http://www.globalccsinstitute.com/publications/costs-ccs-and-other-low-carbon-technologies-2015-update.

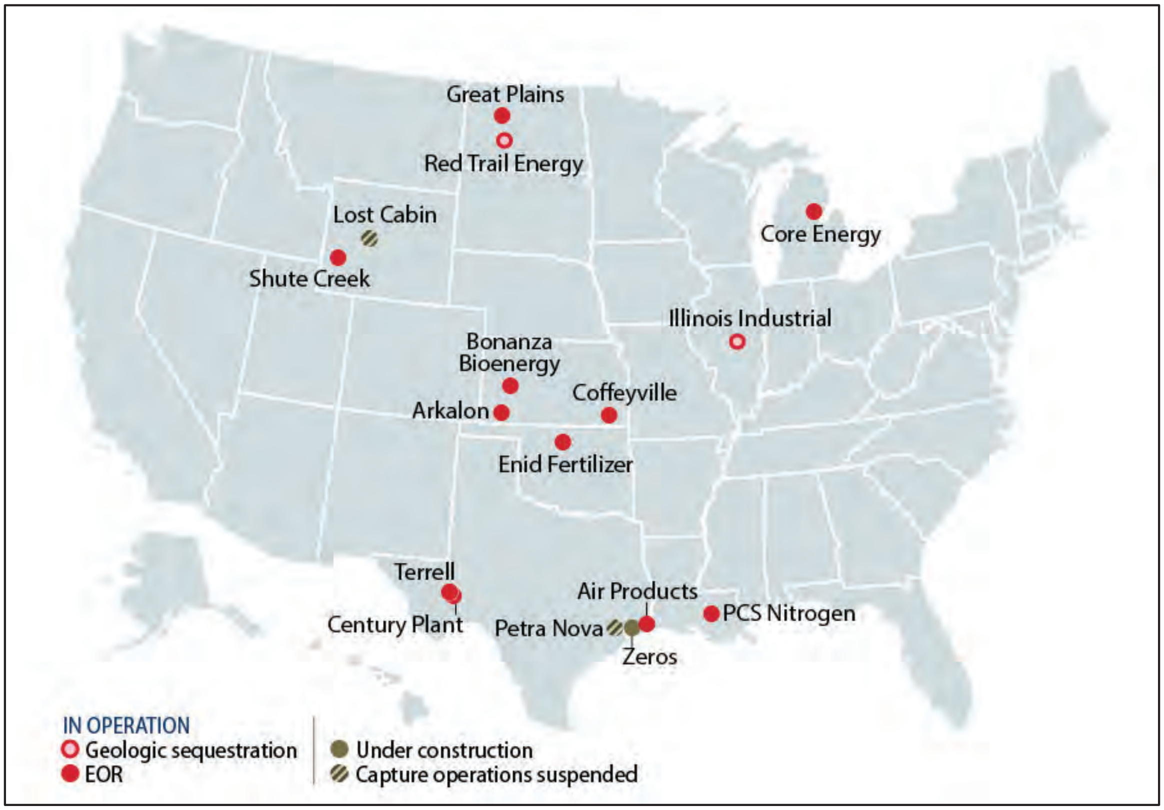
[49] For more information, see CRS In Focus IF11455, *The Tax Credit for Carbon Sequestration (Section 45Q)*, by Angela C. Jones and Molly F. Sherlock.

Commercial CCS Facilities

According to one set of data collected by the Global CCS Institute (GCCSI), 24 commercial facilities were capturing and injecting CO_2 throughout the world in 2021, 12 of which are in the United States.[50] An additional facility, the Red Trail Energy facility, came online in the United States in 2022. See **Figure 6** for locations of U.S. projects capturing and injecting CO_2 for either EOR or geologic sequestration, some of which are not in operation.

Figure 6. Location of U.S. Carbon Capture and Injection Projects

EOR and Geologic Sequestration



Source: CRS, using data from the Global CCS Institute, *Global Status Report 2021*, 2021, and the University of North Dakota Energy & Environment Research Center at undeerc.org.

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50 Global CCS Institute, *Global Status Report 2021*, December 1, 2021; and North Dakota Industrial Commission, *Class VI - Geologic Sequestration Wells,* accessed October 4, 2022, at https://www.dmr.nd.gov/dmr/oilgas/ClassVI . The 13 facilities in operation do not include two facilities, Petra Nova and Lost Cabin, that stopped CCS operations in 2020, or the Zeros facility, which is under construction. The Global CCS Institute defines a *commercial facility* as a facility capturing CO_2 for permanent storage as part of an ongoing commercial operation that generally has an economic life similar to the host facility whose CO_2 it captures, and that supports a commercial return while operating and/or meets a regulatory requirement.

These facilities reportedly have a cumulative capacity to capture an estimated 40 million metric tons of CO_2 each year.[51] Additionally, according to GCCSI, one commercial facility was under construction and 15 projects were in advanced development in the United States, as of 2021.[52]

U.S. capture and injection facilities in operation or under development occur in seven industrial sectors, according to GCCSI data: chemical production, hydrogen production, fertilizer production, natural gas processing, and power generation.[53] Until spring of 2022, the Archer Daniels Midland (ADM) facility in Decatur, IL (also known as the Illinois Industrial Project), was the only facility injecting CO_2 solely for geologic sequestration. The facility injects CO_2 captured from ethanol production into a saline reservoir and as of 2021 reported that 2 million metric tons of CO_2 had been injected at the site.[54] In 2022, North Dakota issued a Class VI permit for CO_2 injection by Red Trail Energy in Richardton, ND. The company plans to capture and inject 180,000 tons of CO_2 per year into an on-site formation for geologic sequestration.[55] See **Figure 7** for additional information on the timeline and industrial sectors for CO_2 capture and injection facilities in the United States.

[51] Global CCS Institute, *Global Status Report 2021,* p. 62.

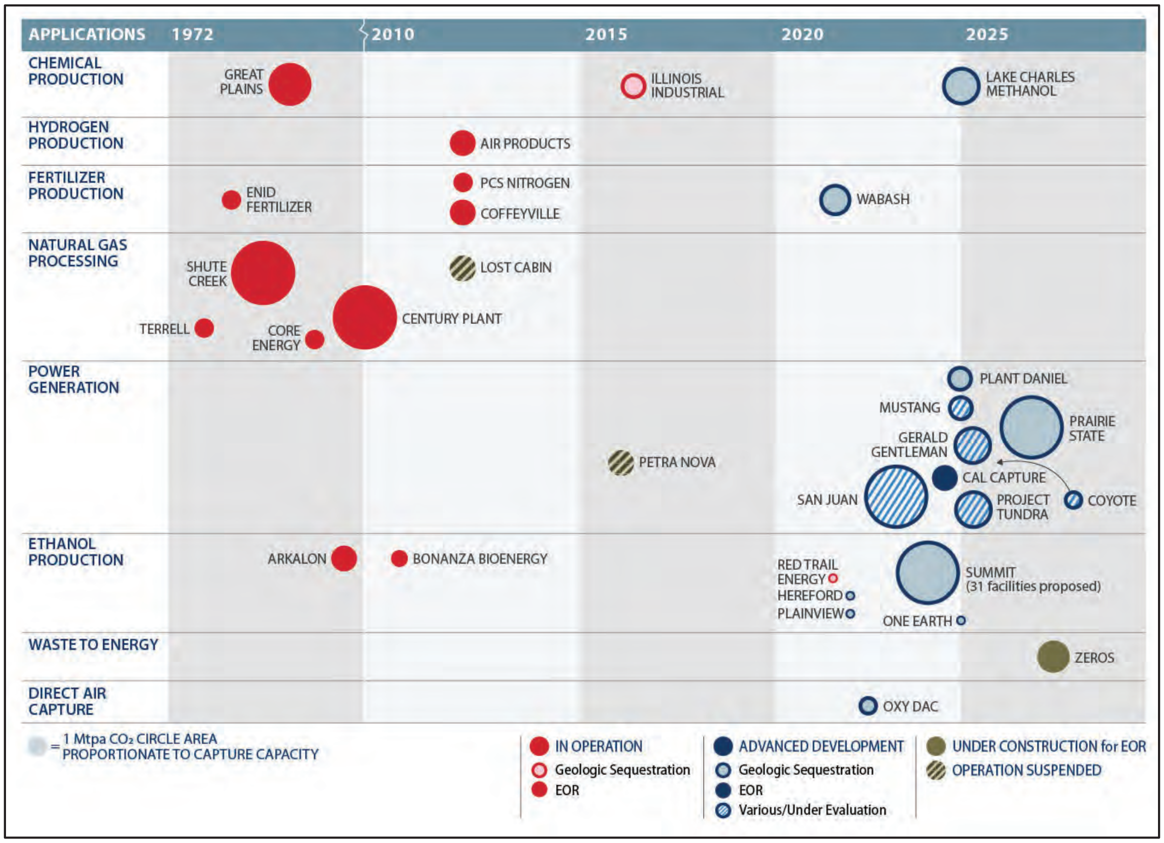
[52] Global CCS Institute, *Global Status Report 2021*, pp. 63-64. GSSCI does not define "advanced development" in this report.

[53] Global CCS Institute, *Global Status Report 2020*. "Under development" indicates that some project development activity has occurred (e.g., feasibility or design studies), but the facility is not actively capturing and/or injecting CO_2 Projects may be in different stages of development.

[54] EPA FLIGHT database, accessed March 14, 2022.

[55] Industrial Commission of North Dakota, "North Dakota Approves First Carbon Capture and Storage Project Under State Primacy in the United States," accessed August 1, 2022, at www.nd.gov/ndic/ic-press/News-DMR211019.pdf.

Figure 7. Operational, Planned, and Suspended Facilities in the United States Injecting CO_2 for Geologic Sequestration and EOR



Source: CRS, adapted from Global CCS Institute, *Global Status Report 2021*, 2021; GSSCI does not define "advanced development" in this report. Red Trail Energy information from the Industrial Commission of North Dakota.

Notes: Mtpa = million tons per annum (year); circle placement indicates initial year of operations or anticipated initial year of operations for projects under development, according to GCCSI (the first time frame in the figure represents 38 years, while the other time frames each represent a five-year period). Some projects under development anticipate multiple CO_2 sources; in these cases, circle placement indicates the initial application being studied.

Stakeholders have paid particular attention to two power generation projects: Boundary Dam, in Saskatchewan, Canada, and Petra Nova, near Houston, TX. Both projects involved retrofitting coal-fired electricity generators with carbon capture equipment and have been noted as examples of carbon capture technology. At the same time, both projects have been criticized for high costs, relative to other low-carbon technologies for electricity generation, and for sequestering carbon via EOR.[56] In May 2020, Petra Nova's owners stopped operating the CCS equipment, citing unfavorable economics due to low crude oil prices, though reports suggest the facility may have experienced prior mechanical challenges.[57]

[56] See, for example, Food & Water Watch, "Top 5 Reasons Carbon Capture and Storage (CCS) Is Bogus," July 20, 2021.

[57] Jeremy Dillon and Carlos Anchondo, "Low Oil Prices Force Petra Nova Into 'Mothball Status,'" *E&E News*, July 28, 2020; and Nichola Groom, "Problems Plagued U.S. CO2 Capture Project Before Shutdown: DOE Document," Reuters, August 6, 2020.

Petra Nova: The First Large U.S. Power Plant with CCS

On January 10, 2017, the Petra Nova–W.A. Parish Generating Station became the first industrial-scale coal-fired power plant with CCS to operate in the United States. The plant began capturing 5,200 short tons (approximately 4,717 metric tons) of CO_2 per day from its 240-megawatt-equivalent slipstream using post combustion capture technology.[58] The capture technology was designed to be approximately 90% efficient (i.e., designed to capture about 90% of the CO_2 in the exhaust gas after the coal was burned to generate electricity) and was designed to capture 1.4 million metric tons of CO_2 each year.[59] The captured CO_2 was transported via an 82-mile pipeline to the West Ranch oil field, where it was injected for EOR. NRG Energy Inc., and JX Nippon Oil & Gas Exploration Corporation, the joint owners of the Petra Nova project, together with Hilcorp Energy Company (which handled the injection and EOR), anticipated increasing West Ranch oil production from 300 barrels per day before EOR to 15,000 barrels per day after EOR.[60] However, Petra Nova's operators turned off the CCS equipment in May 2020, citing low oil prices caused, in part, by the COVID-19 pandemic.[61] In January 2021, the operators announced plans to indefinitely shut down the CCS equipment's power source.[62] As of October 2022, Petra Nova remains out of service.[63]

DOE provided Petra Nova with more than $160 million from its Clean Coal Power Initiative (CCPI) Round 3 funding, using funds appropriated under the American Recovery and Reinvestment Act of 2009 (ARRA; P.L. 111-5) together with other DOE funding for a total of more than $190 million of federal funds for the $1 billion retrofit project.[64] Petra Nova is the only CCPI Round 3 project that expended its ARRA funding and began operating.[65] The three other CCPI Round 3 demonstration projects funded using ARRA appropriations (as well as the FutureGen project—slated to receive nearly $1 billion in ARRA appropriations) all have been canceled, have been suspended, or remain in development.[66]

[58] *Slipstream* refers to the exhaust gases emitted from the power plant. U.S. Department of Energy (DOE), *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project Final Scientific/Technical Report*, March 31, 2020, p. 3.

[59] DOE, "Petra Nova CCS Project."

[60] NRG News Release, "NRG Energy, JX Nippon Complete World's Largest Post-Combustion Carbon Capture Facility On-Budget and On-Schedule," January 10, 2017, at http://investors.nrg.com/phoenix.zhtml?c=121544&p=irol-newsArticle&ID=2236424.

[61] L.M.Sixel, "NRG Mothballs Carbon Capture Project at Coal Plant," *Houston Chronicle*, July 31, 2020.

[62] "Power Plant Linked to Idled U.S. Carbon Capture Project Will Shut Indefinitely," Reuters, January 29, 2021, https://finance.yahoo.com/news/power-plant-linked-idled-u-204526410.html.

[63] Corbin Hiar and Carlos Anchondo, "Biggest CCS Failure Clouds Supreme Court Ruling," E&E News, July 11, 2022.

[64] U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL), "Recovery Act: Petra Nova Parish Holdings: W.A. Parish Post-Combustion CO2 Capture and Sequestration Project," at https://www.netl.doe.gov/research/coal/project-information/fe0003311.

[65] For an analysis of carbon capture and sequestration (CCS) projects funded by the American Recovery and Reinvestment Act (P.L. 111-5), see CRS Report R44387, *Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects*, by Peter Folger.

[66] FutureGen is discussed in more detail in CRS Report R44387, *Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects*, by Peter Folger.

Boundary Dam: World's First Addition of CCS to a Large Power Plant

The Boundary Dam project was the first commercial-scale power plant with CCS in the world to begin operations. Boundary Dam, a Canadian venture operated by SaskPower,[67] cost approximately $1.5 billion, according to one source, though it was originally estimated to cost $1.3 billion.[68] Of the originally estimated amount, $800 million was for building the CCS process and the remaining $500 million was for retrofitting the Boundary Dam Unit 3 coal-fired generating unit. The project also received $240 million from the Canadian federal government. Boundary Dam started operating in October 2014, after a four-year construction and retrofit of the 150-megawatt generating unit. The final project was smaller than earlier plans to build a 300-megawatt CCS plant, but that original idea may have been projected to cost as much as $3.8 billion. The larger-scale project was discontinued because of the escalating costs.[69]

Boundary Dam captures, transports, and sells most of its CO_2 for EOR, shipping 90% of the captured CO_2 via a 41-mile pipeline to the Weyburn Field in Saskatchewan. CO_2 not sold for EOR is injected and stored about 2.1 miles underground in a deep saline aquifer at a nearby experimental injection site. By March 2022, the plant had captured over 4.3 million metric tons of CO_2 since full-time operations began in October 2014.[70] The project injected 370,000 metric tons of CO_2 for geologic sequestration as of 2021.[71]

The DOE CCS Program

DOE has funded R&D of aspects of the three main steps of an integrated CCS system since at least 1997, primarily through its Fossil Energy and Carbon Management Research, Development, Demonstration, and Deployment program (FECM).[72] CCS-focused R&D has come to dominate the coal program area within DOE FECM since 2010. Since FY2010, Congress has provided $9.2 billion (in constant 2022 dollars) total in annual appropriations for FECM (see **Table 2**).[73]

[67] SaskPower is the principal electric utility in Saskatchewan, Canada.

[68] MIT Carbon Capture & Sequestration Technologies, CCS Project Database, "Boundary Dam Fact Sheet: Carbon Capture and Storage Project," at http://sequestration.mit.edu/tools/projects/boundary_dam.html.

[69] Ibid.

[70] SaskPower, *BD3 Status Update: March 2022*, at https://www.saskpower.com/about-us/our-company/blog/2022/bd3-status-update-march-2022.

[71] Petroleum Technology Research Center, *Annual Report 2020-2021*, at https://ptrc.ca/pub/docs/annual-reports/Annual%20Report%202020-21-%20Final_sm.pdf.

[72] DOE has also funded some CCS and carbon removal research through its Advanced Research Projects Agency – Energy. The Fossil Energy and Carbon Management Research, Development, Demonstration, and Deployment appropriations account was previously known as the Fossil Energy Research and Development (FER&D) account. The Biden Administration renamed the Office of Fossil Energy as the Office of Fossil Energy and Carbon Management in 2021. This name change was also adopted by appropriators throughout the FY2022 appropriations process. See DOE, "Our New Name Is Also a New Vision," July 8, 2021, at https://www.energy.gov/fe/articles/our-new-name-also-new-vision.

[73] For information on FY2021 and FY2022 appropriations, see CRS In Focus IF11861, *DOE's Carbon Capture and Storage (CCS) and Carbon Removal Programs*, by Ashley J. Lawson.

Table 2. Annual Appropriations for DOE Fossil Energy and Carbon Management (FECM) Research, Development, Demonstration, and Deployment Program Areas

FY2010 through FY2022 (in thousands of nominal dollars)

FECM Program Areas	Program/ Activity	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022
CCUS and Power Systems	**Carbon Capture**	—	58,703	66,986	63,725	92,000	88,000	101,000	101,000	100,671	100,671	117,800	86,300	99,000
	Carbon Dioxide Removal												40,000	49,000
	Carbon Utilization												23,000	29,000
	Carbon Storage	—	120,912	112,208	106,745	108,766	100,000	106,000	95,300	98,096	98,096	100,000	79,000	97,000
	Advanced Energy and Hydrogen Systems	—	168,627	97,169	92,438	99,500	103,000	105,000	105,000	112,000	129,683	120,000	108,100	94,000
	Cross-Cutting Research	—	41,446	47,946	45,618	41,925	49,000	50,000	45,500	58,350	56,350	56,000	32,900	33,000
	Mineral Sustainability	—	—	—	—	—	—	—	—	—	—	—	53,000	53,000
	Supercritical CO_2 Technology	—	—	—	—	—	10,000	15,000	24,000	24,000	22,430	16,000	14,500	15,000
	NETL Coal R&D	—	—	35,011	33,338	50,011	50,000	53,000	53,000	53,000	54,000	61,000	0	
	Transformational Coal Pilots[a]	—	—	—	—	—	—	—	50,000[a]	35,000	25,000	20,000	10,000	0
Subtotal CCUS and Power Systems		**393,485**	**389,688**	**359,320**	**341,864**	**392,202**	**400,000**	**430,000**	**473,800**	**481,117**	**486,230**	**490,800**	**446,800**	**469,000**
Other FECM	**Natural Gas Technologies**	17,364	0	14,575	13,865	20,600	25,121	43,000	43,000	50,000	51,000	51,000	57,000	0

FECM Program Areas	Program/ Activity	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017	FY2018	FY2019	FY2020	FY2021	FY2022
	Unconventional Fossil Energy Technologies from Petroleum – Oil Technologies	19,474	0	4,859	4,621	15,000	4,500	20,321	21,000	40,000	46,000	46,000	46,000	0
	Resource Technologies and Sustainability													110,000
	Program Direction	158,000	164,725	119,929	114,201	120,000	119,000	114,202	60,000	60,000	61,070	61,500	61,500	66,800
	Plant and Capital	20,000	19,960	16,794	15,982	16,032	15,782	15,782	—	—	—	—	—	
	Env. Restoration	10,000	9,980	7,897	7,515	5,897	5,897	7,995	—	—	—	—	—	
	Special Recruitment	700	699	700	667	700	700	700	700	700	700	700	700	1,001
	NETL Research and Operations	—	—	—	—	—	—	0	43,000	50,000	50,000	50,000	83,000	83,000
	NETL Infrastructure	—	—	—	—	—	—	0	40,500	45,000	45,000	50,000	55,000	75,000
	Coop R&D	4,868	—	—	—	—	—	—	—	—	—			
	Directed Projects	35,879	—	—	—	—	—	—	—	—	—			20,199
Subtotal Other FECM		**266,285**	**195,364**	**164,754**	**156,851**	**178,229**	**171,000**	**202,000**	**208,200**	**245,700**	**253,770**	**259,200**	**303,200**	**356,000**
Rescissions/Use of Prior-Year Balances		—	(151,000)	(187,000)	—	—	—	—	(14,000)	—	—			
Total FECM		**659,770**	**434,052**	**337,074**	**498,715**	**570,431**	**571,000**	**632,000**	**668,000**	**726,817**	**740,000**	**750,000**	**750,000**	**825,000**
Total FECM (Q2 2022 dollars)		**832,547**	**533,715**	**409,144**	**598,581**	**669,712**	**669,402**	**740,721**	**766,636**	**809,515**	**809,032**	**800,863**	**781,295**	**825,000**

Sources: U.S. Department of Energy annual budget justifications for FY2012 through FY2023; explanatory statement for P.L. 115-141, Division D (Consolidated Appropriations Act, 2018, at https://rules.house.gov/bill/115/hr-1625-sa); explanatory statement for P.L. 117-30 (Consolidated Appropriations Act, 2022, Division D).

Notes: CO_2 = carbon dioxide; CCUS = carbon capture utilization and sequestration (or storage); FECM = Fossil Energy and Carbon Management Research, Development, Demonstration, and Deployment program; NETL = National Energy Technology Laboratory; Inf. & Ops = infrastructure and operations; Coop = cooperative; R&D = research and development. Directed Projects refer to congressionally directed projects. Program areas are as used in the explanatory statement for FY2022 appropriations; previous appropriations language used alternative names for some program areas and may not be completely comparable. Supplemental appropriations provided by the American Recovery and Reinvestment Act of 2009 (ARRA; P.L. 111-5) and the Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) are not shown in the table. The carbon utilization program was first authorized for FY2021 as part of P.L. 116-260. The line items for Carbon Dioxide Removal and Resource Technologies and Sustainability were first used in FY2022 appropriations. Nominal dollars adjusted to Q2 2022 dollars using the price index for federal government investment in research and development from Bureau of Economic Analysis, "National Income and Product Accounts," Table 3.9.4.

a. Funding for Transformational Coal Pilots was first provided as a proviso in FY2017 appropriations. See explanatory statement for P.L. 115-31, Consolidated Appropriations Act, 2017, Division D at https://www.gpo.gov/fdsys/pkg/CPRT-115HPRT25289/pdf/CPRT-115HPRT25289.pdf.

Congress has additionally provided supplemental funding for DOE's CCS activities. The American Recovery and Reinvestment Act of 2009 (ARRA; P.L. 111-5) provided an additional $3.4 billion ($4.4 billion in 2022 dollars), specifically for CCS projects.[74] The Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) provided $8.5 billion (nominal dollars) in supplemental funding for CCS for FY2022-FY2026 (see **Table 3**), including funding for the construction of new carbon capture facilities and commercial carbon storage facilities. Additionally, IIJA provided $3.6 billion (nominal dollars) in supplemental funding for DAC, primarily to support the establishment of four regional direct air capture hubs in the United States.[75]

Table 3. Infrastructure Investment and Jobs Act Supplemental Appropriations for Carbon Capture and Storage Programs

FY2022 through FY2026 (in thousands of nominal dollars)

Program	Unspecified Year	FY2022	FY2023	FY2024	FY2025	FY2026	Total FY2022-FY2026
Front-End Engineering and Design (carbon capture)		20,000	20,000	20,000	20,000	20,000	100,000
Carbon Capture Large-Scale Pilot Projects		387,000	200,000	200,000	150,000	—	937,000
Carbon Capture Demonstration Projects		937,000	500,000	500,000	600,000	—	2,537,000
Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA)		3,000	2,097,000	—	—	—	2,100,000
Carbon Utilization		41,000	65,250	66,563	67,941	69,388	310,141
Carbon Storage Validation and Testing		500,000	500,000	500,000	500,000	500,000	2,500,000
U.S. Environmental Protection Agency Class VI Injection Well Program	50,000	5,000	5,000	5,000	5,000	5,000	75,000

Source: Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58), Division J.

[74] Authority to expend American Recovery and Reinvestment Act (ARRA; P.L. 111-5) funds expired in 2015. An analysis of ARRA funding for CCS activities at DOE is provided in CRS Report R44387, *Recovery Act Funding for DOE Carbon Capture and Sequestration (CCS) Projects*, by Peter Folger.

[75] The Infrastructure Investment and Jobs Act (IIJA; P.L. 117-58) defined a regional direct air capture hub as "a network of direct air capture projects, potential carbon dioxide utilization off-takers, connective carbon dioxide transport infrastructure, subsurface resources, and sequestration infrastructure located within a region." 42 U.S.C. §16298d(j).

Notes: Programs are within the U.S. Department of Energy (DOE), except for the U.S. Environmental Protection Agency's (EPA's) Class VI injection well program, which permits wells for geological sequestration of carbon dioxide. Some DOE programs are administered by the Office of Fossil Energy and Carbon Management (FECM), while others are administered by the Office of Clean Energy Demonstrations. IIJA additionally provided $3,500,000,000 ($700 million each year, FY2022-FY2026) to develop four regional clean direct air capture hubs and $115 million (unspecified year) for direct air capture technology prize competitions. Both programs are to be administered by FECM. All funds are to remain available until expended.

A 2021 evaluation by the Government Accountability Office (GAO) found several cost control risks related to DOE's past management of its CCS program, particularly DOE's implementation of ARRA.[76] These risks included a high-risk selection process, an accelerated schedule of project review, and the bypassing of internal cost controls. GAO found DOE used less risky processes in awarding CCS funding for industrial projects as compared to coal projects. Partly as a result, two out of three funded industrial CCS projects were operational in 2021, while none of the eight funded coal projects was operational. GAO noted that economic factors, such as declines in natural gas prices, affected coal projects more than industrial projects, and also contributed to withdrawal or cancellation of DOE-funded coal projects.

EPA Regulation of Underground Injection in CCS

EPA issues regulations for underground injection of CO_2 as part of its responsibilities for underground injection control (UIC) programs under the Safe Drinking Water Act (SDWA). EPA also develops guidance to support state program implementation, and in some cases, directly administers UIC programs in states.[77] The agency has established minimum requirements for state UIC programs and permitting for injection wells. These requirements include performance standards for well construction, operation and maintenance, monitoring and testing, reporting and recordkeeping, site closure, financial responsibility, and, for some types of wells, post injection site care. Most states implement the day-to-day program elements for most categories of wells, which are grouped into "classes" based on the type of fluid injected. Owners or operators of underground injection wells must follow the permitting requirements and standards established by the UIC program authority in their state.

EPA has issued regulations for six classes of underground injection wells based on type and depth of fluids injected and potential for endangerment of underground sources of drinking water (USDWs). Class II wells are used to inject fluids related to oil and gas production, including injection of CO_2 for EOR. There are more than 119,500 EOR wells in the United States, predominantly in California, Texas, Kansas, Illinois, and Oklahoma.[78] This total includes EOR wells that can be used to inject CO_2 captured from anthropogenic sources and wells using naturally derived CO_2. Class VI wells are used to inject CO_2 for geologic sequestration. Two EPA-permitted Class VI wells are currently operating for sequestration in the United States, both located at the ADM facility in Illinois.[79] In 2022, North Dakota, which has delegated authority for its UIC Class VI well program, issued two CO_2 injection permits for geologic sequestration.

[76] U.S. Government Accountability Office, *Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects*, December 2021.

[77] 40 C.F.R. §§144-147.

[78] EPA, *FY19 State UIC Injection Well Inventory*, accessed April 11, 2021.

[79] EPA has granted North Dakota and Wyoming primary enforcement authority for Class VI well programs in those states.

To protect USDWs from injected CO_2 or movement of other fluids in an underground formation, Class II EOR wells must transition to Class VI geologic sequestration wells under certain conditions.[80] Class II well owners or operators who inject CO_2 primarily for long-term storage (rather than oil production) must obtain a Class VI permit when there is an increased risk to USDWs compared to prior Class II operations using CO_2. The Class VI Program Director (EPA or a delegated state) determines whether a Class VI permit is required based on site-specific risk factors associated with USDW endangerment. To date, no such transition has been required.

The 45Q Tax Credit for Carbon Sequestration[81]

Federal tax credits for carbon sequestration were first authorized in 2008 with the enactment of the Energy Improvement and Extension Act (Division B of P.L. 110-343). This act added Section 45Q to the Internal Revenue Code (I.R.C), which established tax credits for CO_2 disposed of in "secure geologic storage" or through EOR with secure geologic storage.[82] The Bipartisan Budget Act of 2018 (BBA; P.L. 115-123) amended Section 45Q to increase the tax credit for capture and sequestration of "carbon oxide," for its use as a tertiary injectant in EOR operations, or for other qualified uses. In 2022, the measure known as the Inflation Reduction Act of 2022 (IRA; P.L. 117-169) made numerous changes to Section 45Q.

Provisions in Section 45Q establish the amount of the tax credit per ton of carbon oxide captured and disposed of, annual CO_2 capture minimums, deadlines for beginning facility construction, and credit claim periods, and direct the U.S. Department of Treasury (Treasury) to issue 45Q regulations, among other provisions. Credit rates, capture minimums, and other provisions differ depending on the type of facility and when the facility or capture equipment was placed in service.

The IRA established the tax rate for facilities or equipment placed in service after December 31, 2022. If projects pay prevailing wages and meet registered apprenticeship requirements, the tax credit amount is $85 per ton of CO_2 disposed of in secure geologic storage and $60 per ton of CO_2 used for EOR and disposed of in secure geologic storage, or utilized in a qualified matter.[83] For DAC facilities or equipment placed in service after December 31, 2022, that pay prevailing wages and meet registered apprenticeship requirements, the credit is $180 per ton for CO_2 disposed of in secure geologic storage and $130 per ton for CO_2 that is used for EOR and disposed of in secure geologic storage, or utilized in a qualified manner.[84] Credit amounts are adjusted for inflation after 2026. To qualify for tax credits, a point source facility or DAC facility must begin construction by December 31, 2032.[85] The credit can be claimed over a 12-year period after operations begin.

The IRA increased the credit from the rates that had been established in the BBA. Before the IRA, and for facilities placed in service before 2023, the Section 45Q tax credit amount increases linearly from $22.66 to $50 per ton over the period from calendar year 2017 until calendar year 2026 for CO_2 captured and disposed of in secure geologic storage, and from $12.83 to $35 per ton over the same period for CO_2 captured and used as a tertiary injectant for EOR or for another qualified use, with tax credit amounts adjusted for inflation after 2026.

A facility must capture a minimum amount of CO_2 to qualify for tax credits under Section 45Q.[86] For facilities that begin construction after August 16, 2022, DAC facilities must capture at least 1,000 tons of CO_2 per year;

[80] 40 C.F.R. §144.19.

[81] For additional background, see CRS InFocus IF11455, *The Tax Credit for Carbon Sequestration (Section 45Q)*, by Angela C. Jones and Molly F. Sherlock.

[82] 26 U.S.C §45Q. P.L. 115-123 expanded the tax credit to all carbon oxides, which includes CO_2 and carbon monoxide.

[83] P.L. 117-169, §13104(b). For facilities that do not meet prevailing wage and apprenticeship requirements, the base credit amount is $17 per ton for secure geologic storage and $12 per ton for EOR or other qualified use.

[84] P.L. 117-169, §13104(c). Prior to the IRA amendments, eligible taxpayers disposing of CO_2 captured through DAC would have received the credit amount for the type of disposal used, either geologic sequestration or EOR/utilization. For facilities or equipment placed in service after December 31, 2022, the base credit amount established in the IRA is $36 per ton for CO_2 captured using DAC with geological sequestration and $26 per ton for CO_2 captured using DAC with EOR or qualified utilization.

[85] P.L. 117-169, §13104(a).

[86] Taxpayers must physically or contractually dispose of captured carbon oxide in secure geological storage. See IRS Prop. Reg. §1.45Q-1, Prop. Reg. §1.45Q-2, Prop. Reg. §1.45Q-3, Prop. Reg. §1.45Q-4, and Prop. Reg. §1.45Q-5; and

electricity generating facilities must capture at least 18,750 tons of CO_2 per year and have a capture design capacity at least 75% of the unit's baseline carbon oxide production; and other facilities must capture at least 12,500 tons of CO_2 per year.[87] The amounts established in the IRA are less than what had previously been required. For facilities that began construction by August 16, 2022, and are covered under the BBA, an electricity generating facility that emits more than 500,000 tons of CO_2 per year must capture a minimum 500,000 tons of CO_2 annually to qualify for the tax credit. A facility that captures CO_2 for the purposes of utilization—fixing CO_2 through photosynthesis or chemosynthesis, converting it to a material or compound, or using it for any commercial purpose other than tertiary injection or natural gas recovery (as determined by the Secretary of the Treasury)—and emits less than 500,000 tons of CO_2 must capture at least 25,000 tons per year. A direct air capture facility or a facility that does not meet the other criteria just described must capture at least 100,000 tons per year.

Tax-exempt entities, including state and local governments and electric cooperatives, can elect to receive the Section 45Q tax credits as "direct pay." This allows these entities to receive the credit amount as a payment, instead of a reduction in tax liability. The IRA allows direct pay for CO_2 captured at facilities placed in service after December 31, 2022. Taxpayers also may be able to elect to receive the Section 45Q tax credit as direct pay, for up to five years, but not after 2032. Taxpayers can also elect to make a one-time transfer of the credit. For equipment placed in service after February 9, 2018, the credit is attributable to the person who owns the carbon capture equipment and physically or contractually ensures the disposal or use of the qualified CO_2. The credits can be transferred to the person who disposes of or uses the qualified CO_2.

Some stakeholders have suggested that the tax credit increases in Section 45Q could be a "game changer" for CCS developments in the United States, by providing incentives sufficient to drive investments in CO_2 capture and storage.[88] They note that EOR has been the main driver for CCS development, and the new tax credit incentives might result in an increased shift toward CO_2 capture for permanent storage, apart from EOR.

Opponents to 45Q include some environmental groups that broadly oppose measures that extend the life of coal-fired power plants or provide incentives to private companies to increase oil production.[89] Another factor to consider is the cost. Over the FY2022-FY2031 budget window, Treasury estimates that the tax credit will reduce federal income tax revenue by a total of $20.1 billion.[90] Other groups note that measures in addition to the 45Q tax credits will be needed to lower CCS costs and promote broader deployment.

The Internal Revenue Service (IRS) continues to issue guidance and promulgate regulations on implementation of the Section 45Q tax credit. In January 2021, the IRS issued final regulations on demonstration of "secure geologic storage," utilization of qualified carbon oxide, eligibility, and credit recapture, among other provisions (86 *Federal Register*, January 15, 2021, 4728-4773). The IRS may issue further Section 45Q guidance related to changes enacted in the IRA in the future.

Department of the Treasury, "Credit for Carbon Oxide Sequestration," 85 *Federal Register* 34050-34075, June 2, 2020.

[87] P.L. 117-169, §13104(a). For equipment placed in service after the enactment of the BBA on February 9, 2018, and before January 1, 2023, the annual capture requirements are (1) in the case of a facility that emits no more than 500,000 metric tons of carbon oxide, capture at least 25,000 metric tons of carbon oxide that is either fixated through the growing of algae or bacteria, chemically converted into a material or chemical compound in which the carbon oxide is stored, or used for another commercial purpose (other than a tertiary injectant); (2) in the case of an electricity generating facility not described in (1), capture at least 500,000 metric tons of carbon oxide per year; or (3) in the case of a direct air capture facility not described in (1) or (2), capture at least 100,000 metric tons of carbon oxide. For equipment placed in service before February 9, 2018, the capture requirement is 500,000 tons per year.

[88] Emma Foehringer Merchant, "Can Updated Tax Credits Bring Carbon Capture Into the Mainstream?," *Greentech Media*, February 22, 2018; James Temple, "The Carbon Capture Era May Finally Be Starting," *MIT Technology Review*, February 20, 2018.

[89] Natural Resources Defense Council, "Capturing Carbon Pollution While Moving Beyond Fossil Fuels," accessed on November 27, 2019, at https://www.nrdc.org/experts/david-doniger/capturing-carbon-pollution-while-moving-beyond-fossil-fuels; Richard Conniff, "Why Green Groups are Split on Subsidizing Carbon Capture Technology," *YaleEnvironment360*, April 9, 2018.

[90] U.S. Department of the Treasury, "FY2023 Tax Expenditures," accessed February 17, 2022, at https://home.treasury.gov/policy-issues/tax-policy/tax-expenditures.

Discussion

In recent Congresses, proposed and enacted CCS-related legislation has addressed federal CCS research and development (R&D) activities and funding, CO_2 pipelines, and the carbon sequestration tax credit. Bills, or provisions thereof, addressing CCS were enacted as part of the Consolidated Appropriations Act, 2021 (P.L. 116-260). Potential implementation and oversight issues related to these provisions might be of interest in the 117th Congress and beyond.

In the 116th Congress, as part of the Consolidated Appropriations Act, 2021 (P.L. 116-260), Congress reauthorized the DOE CCS research program. Among other provisions, the law expanded the scope of DOE's research to noncoal applications (e.g., natural gas-fired power plants, other industrial facilities).[91] The law also authorized a DOE carbon utilization research program and specific activities related to direct air capture (e.g., a DAC technology prize). IIJA built upon this expanded scope, providing supplemental appropriations for several programs authorized by P.L. 116-260, and established new CCS and DAC programs. As is also true for other DOE applied research programs, some criticize such activities as an inappropriate role for government, arguing the private sector is better suited to develop technologies that can compete in the marketplace.[92]

Council on Environmental Quality 2021 CCS Report to Congress and 2022 CCS Guidance

In response to the USE IT Act, in 2021, the White House Council on Environmental Quality (CEQ) provided Congress with a report on carbon capture, utilization, and sequestration project permitting and review.[93] One of several reports required by Congress in the Consolidated Appropriations Act, 2021 (P.L. 116-260), this report provides information on federal permitting and regulations for CCS projects and examines technical, financial, and policy-related issues for project deployment. In its key findings, CEQ states that "CCUS has a critical role to play in decarbonizing the global economy" and that "President Biden is committed to accelerating the responsible development and deployment of carbon capture, utilization, and permanent sequestration as needed to decarbonize the U.S. economy by mid-century."[94] CEQ also finds that to be beneficial, CCS projects must be "well-designed and well governed."[95] Regarding governance, CEQ also finds that the existing federal regulatory framework is "rigorous and capable of managing permitting and review actions while protecting the environment, public health, and safety as CCUS projects move forward."[96]

In February 2022, CEQ released an interim guidance, *Carbon Capture, Utilization, and Sequestration Guidance*, also as directed by Congress in the USE IT Act.[97] The interim guidance

[91] For additional information, see CRS In Focus IF11861, *DOE's Carbon Capture and Storage (CCS) and Carbon Removal Programs*, by Ashley J. Lawson.

[92] See, for example, Heritage Foundation, "Eliminate the DOE Office of Fossil Energy," in *Budget Blueprint for FY2022*.

[93] CEQ, *Council on Environmental Quality Report to Congress on Carbon Capture, Utilization, and Sequestration*, https://www.whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf. The report to Congress is required by P.L. 116-260, Division S, §102.

[94] CEQ CCS Report, p. 8.

[95] CEQ CCS Report, p. 8.

[96] CEQ CCS Report, p. 8.

[97] Council on Environmental Quality, "Carbon Capture, Utilization, and Sequestration Guidance," 87 *Federal Register*

includes recommendations for federal agencies that would support "the efficient, orderly, and responsible development and permitting of CCUS projects at an increased scale in line with the Administration's climate, economic, and public health goals."[98] In the document, CEQ provides guidance to federal agencies on the processes for permitting and review of CCS projects and CO_2 pipelines, public engagement, and assessing environmental impacts of CCS projects.

Other CCS Policy Issues

With respect to other issues for congressional consideration, costs have been, and remain, a key challenge to CCS development in the United States. In recent years, Congress has attempted to address this challenge in two main ways—federal R&D and federal tax credits. P.L. 116-260 and P.L. 117-169 also extended the start of construction deadline for facilities claiming the 45Q tax credit. In January 2021, the IRS promulgated regulations establishing requirements for carbon storage under Section 45Q. Congress remains interested in the efficacy of the tax credit in promoting CCS development and could consider additional adjustments.

The issue of expanded CCS deployment is closely tied to the issue of reducing greenhouse gas emissions to mitigate human-induced climate change. In 2021, the Biden Administration announced climate change mitigation goals and strategies, and new climate-focused groups and initiatives that may also be of interest when considering CCS-related oversight, appropriations, or legislation. In two executive orders signed in January 2021, President Biden outlined new federal climate policies; created new White House and Department of Justice climate offices; and established new task forces, workgroups, and advisory committees on climate change science and policy.[99] At this early stage, the implications of these executive branch policies and actions on CCS project development and deployments are unclear.

The use of CCS technology as a greenhouse gas emissions reduction approach is not uniformly supported by advocates for actions to address climate change.[100] Some argue that CCS supports continued reliance on fossil fuels, which runs counter to their view of how to reduce greenhouse gas emissions and meet other environmental goals. They tend to prefer policies that phase out the use of fossil fuels altogether. Others raise concerns about the long-term safety and environmental uncertainties of injecting large volumes of CO_2 underground.

8808-8811, February 16, 2022. The CEQ guidance is required by P.L. 116-260, Division S, §102.

[98] Council on Environmental Quality, "Carbon Capture, Utilization, and Sequestration Guidance," 87 *Federal Register* 8808-8811, February 16, 2022, p. 8809.

[99] Executive Order 13990, *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,* January 20, 2021; and Executive Order 14008, *Tackling the Climate Crisis at Home and Abroad*, January 27, 2021.

[100] For example, in its May 2021 interim final recommendations, the White House Environmental Justice Advisory Council (WHEJAC) listed CCS projects as among those projects that would not benefit communities (WHEJAC, *Justice40, Climate and Economic Justice Screening Tool & Executive Order 12898 Revisions: Interim Final Recommendations,* May 13, 2021). See also Carlos Anchondo, "Industry Warns Lawmakers of CCS Threats," *Energywire*, November 25, 2019; and Richard Conniff, "Why Green Groups Are Split on Subsidizing Carbon Capture Technology," *YaleEnvironment360*, April 9, 2018.

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Acknowledgments

CRS Specialist Paul Parfomak provided substantial contributions to the CO_2 Transport Section of this report. CRS Specialist Peter Folger authored the original version of this report. CRS Intern Claire Mills contributed research related to lifecycle greenhouse gas emissions for different enhanced oil recovery processes.

Disclaimer

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December 13, 2022

Christopher M. Bzdok
OLSON, BZDOK & HOWARD, P.C.
420 E. Front St.
Traverse City, MI 49686

Re: In the matter of the Application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief
MPSC Case No. U-21193 (Paperless e-file)

Dear Mr. Bzdok:

Attached for electronic filing in the above captioned matter is DTE Electric Company's response to the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan First Discovery Request. The attachments to responses are being provided to the respective parties via the following links listed below:

Public Attachments:
https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U21193Public/Documents/Forms/AllItems.aspx

Also attached is the Proof of Service.

Very truly yours,

Lauren D. Donofrio
Digitally signed by Lauren D. Donofrio
Date: 2022.12.13 10:34:45 -05'00'

Lauren D. Donofrio

LDD /erb
Attachments
cc: Service List

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.1
Respondent:	Case Manager
Page:	1 of 1

Question: Please provide the tables and figures embedded in testimony as Excel spreadsheets showing all computations.

Answer: See U-21193 MNSCDE-1.1 attachments.

Attachments:

U-21193 MNSCDE-1.1 Figure and Table References.xlsx
U-21193 MNSCDE-1.1 Carden Testimony Table References.xlsx
U-21193 MNSCDE-1.1 Leuker Tables and Figures.xlsx

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.2
Respondent:	J. Leslie
Page:	1 of 1

Question: In lines 13-16 on page 57 of his direct testimony, Ms. Leslie states that the Company "expects resources to be located in the state of Michigan rather than relying on new or existing resources outside of the state". Does this mean that the Company will not consider resources outside of Michigan no matter the economics of such resources? Please explain your response.

Answer: No, it does not mean the Company will not consider resources outside of Michigan (MISO Zone 7). Given the factors that the Company must consider in order to ensure a reliable supply of power to its customers, it expects that resources will need to be located in Michigan (MISO Zone 7). These factors include (but are not limited to) resource availability, cost, MISO resource adequacy rules, deliverability, and risk. If a resource is external to MISO, an additional consideration is the risk that the capacity of an external resource may not count towards meeting the Company's customer requirements, thus the Company would have to procure additional capacity within MISO Zone 7.

Attachments: N/A

Co-Respondent(s): S. Burgdorf

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.3a
Respondent:	J. Leslie
Page:	1 of 1

Question: The following questions concern the 946 MW natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS) described in lines 10-15 on page 17 of Ms. Leslie's direct testimony.

a. Is the Company aware of any other electric Integrated Resource Plan by any electric utility containing such a resource? If so, please identify and provide those Integrated Resource Plans.

Answer: The Company is not aware and has not performed an exhaustive search for the existence of any other electric utilities that have included CCGT with CCS technologies within their Integrated Resource Plans.

Attachments: None

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.3b
Respondent:	J. Leslie
Page:	1 of 1

Question: The following questions concern the 946 MW natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS) described in lines 10-15 on page 17 of Ms. Leslie's direct testimony.

b. Please provide examples of all such utility-scale CCGT generating units with CCS currently in operation

Answer: The Company is unaware of any utility-scale CCGT generating units with CCS currently in operation.

Attachments: None

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.3c
Respondent:	J. Leslie
Page:	1 of 1

Question: The following questions concern the 946 MW natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS) described in lines 10-15 on page 17 of Ms. Leslie's direct testimony.

c. Please provide examples of all such generating units with CCS of any size currently in operation

Answer: The Company is unaware of any generating units with CCS of any size currently in operation.

Attachments: None

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.3d
Respondent:	J. Leslie
Page:	1 of 1

Question: The following questions concern the 946 MW natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS) described in lines 10-15 on page 17 of Ms. Leslie's direct testimony.

d. Please provide examples of all such generating units with CCS currently under development.

Answer: While DTE Electric cannot know for certain what each and every utility or non-utility may be developing, it is aware of the following:

Per the organization Clean Air Task Force, the Company is aware of the following examples of generating units with CCS currently under development.

Example Projects:

- Calpine's Delta Energy Center (California)
- Chevron's Kern River Eastridge (California)
- Coyote Energy's Coyote Clean Power Project (Colorado)

Available information can be found in: Clean Air Task Force, 2022. US Carbon Capture Activity and Project Map
Source: //www.catf.us./ccsmapus/ accessed 12/6/22

Attachments: None

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.3e
Respondent:	J. Leslie
Page:	1 of 1

Question: The following questions concern the 946 MW natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS) described in lines 10-15 on page 17 of Ms. Leslie's direct testimony.

e. Please provide examples of all such generating units with CCS currently undergoing testings.

Answer: While DTE Electric cannot know for certain what each and every utility or non-utility may be testing, it is aware of the following:

The National Energy Technology Laboratory (NETL) Carbon Capture Program represents the facilitation of Department of Energy-funded FEED (front-end engineering design) Studies as well as collaboration across three carbon capture test centers including the National Carbon Capture Center (NCCC) in Alabama, Technology Centre Mongstad (TCM) in Norway, and Wyoming Integrated Test Center (ITC) in Wyoming.

Example Testing / Studies:

- Southern Co. Natural Gas-Fired Power Plant - DE-FE0031847[1]
- Calpine's Delta Energy Center - DE-FE0032149[2]
- Deer Park Energy Center NGCC - DE-FE0032137[3]
- Calpine's Los Medanos Energy Center (LMEC) - DE-FE0031950[4]

Source Files:
US DOE – NETL. Point Source Carbon Capture from Power Generations
Source: https://netl.doe.gov/carbon-capture/power-generation accessed 12/6/22

1. *US DOE – NETL. Project Landing Page, Source: https://netl.doe.gov/project-information?p=FE0031847 accessed 12/6/22*
2. *US DOE – NETL. Project Landing Page, Source: https://netl.doe.gov/project-information?p=FE0032149 accessed 12/6/22*
3. *US DOE – NETL. Project Landing Page, Source: https://netl.doe.gov/project-information?p=FE0032137 accessed 12/6/22*
4. *US DOE – NETL. Project Landing Page, Source: https://netl.doe.gov/project-information?p=FE0031950 accessed 12/6/22*

Attachments: None

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.4a
Respondent:	L. Mikulan
Page:	1 of 1

Question: On pages 15-17 of her direct testimony, Ms. Mikulan details the Company's Preferred Course of Action ("PCA")

a. For each resource included in the PCA, state whether the resource was selected by the optimization process within the EnCompass model or was selected through another process.

Answer: Each resource included in the PCA was selected in one or more EnCompass optimization runs. For more detail on the process of synthesizing the EnCompass modeling results into the PCA, refer to the testimony of Witness Mikulan, Section VIII, Q118 to Q136.

Attachments: N/A

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.4b
Respondent:	L. Mikulan
Page:	1 of 1

Question: On pages 15-17 of her direct testimony, Ms. Mikulan details the Company's Preferred Course of Action ("PCA")

b. For each resource in the PCA that was not selected by the optimization process within the EnCompass model, please describe the process that was used to select the resource.

Answer: See response to MNSCDE-1.4a.

Attachments: N/A

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.5
Respondent:	S. Manning
Page:	1 of 1

Question: Please provide load and resource tables in Excel spreadsheets for each EnCompass case that supports the Company's direct testimony

Answer: There is a folder for each EnCompass case or run located in U-21193 IRP - NDA Pre-PO that contain load and resource information. For the load, please reference the reports titled "…Company Annual" and for resources, please reference the reports titled "…Resource Annual".

Attachments: *None.*

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.6a
Respondent:	L. Mikulan
Page:	1 of 1

Question: Refer to the discussion of carbon capture and sequestration ("CCS") found on page 23, lines 4 – 14 of Ms. Mikulan's direct testimony.

a. Explain the basis for the contention that a CCGT with CCS plant is expected to capture between 50-98.5% of the carbon it emits.

Answer: DTE Electric engaged the engineering consultant, Black and Veatch, to understand the carbon reduction potential, approximate costs, technical maturity, and other characteristics of various emerging technologies, including the carbon capture and sequestration technology at gas-fired combined (or simple) cycle power generating plants. Please refer to Black and Veatch's study report "Emerging Generation Technologies Road-Mapping Study" in workpaper "WP LKM 1 -DTE Emerging Technologies Road-Mapping Study Report_r3a1_Final", Pages 1-6, 1-10, 1-11, 1-14, and Section 2.13 in pages 2-68 to 2-76. In addition, please refer to workpaper "WP RCG 5 - EPRI Data" for inputs considered for the CCGT with CCS technology into the EnCompass modeling.

In addition, the basis for DTE Electric's expectation of capturing 50-98.5% of carbon emissions is supported by previous coal and natural gas generation projects. One such example is the Bellingham NGCC in Massachusetts which operated from 1991 to 2005 and captured 85-95% of CO_2 that would have otherwise been emitted.

This basis is further supported by the Department of Energy's eligibility requirements which require a 95% carbon capture efficiency for projects that utilize funding available through the Bipartisan Infrastructure Law.

Source Files:
Department of Energy, 2017. Carbon Capture Opportunities for Natural Gas Fired Power Systems, Source:
https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf *accessed 12/6/22*

Department of Energy, 2022. Bipartisan Infrastructure Law: Carbon Capture Demonstration Projects Program (DE-FOA-0002806) Source:
https://netl.doe.gov/node/11881 accessed on 12/6/22

Attachments: *None*

Co-Respondent(s): R. Cejas Goyanes, S. Narayan

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.6b
Respondent:	L. Mikulan
Page:	1 of 1

Question: Refer to the discussion of carbon capture and sequestration ("CCS") found on page 23, lines 4 – 14 of Ms. Mikulan's direct testimony.

b. Identify and produce any analyses, studies, or other documents supporting the contention that CCS can capture between 50% and 98.5% of the carbon that would otherwise be emitted by a CCGT plant.

Answer: Please refer to the response to question MNSCDE-1.6a. In addition, please refer to the links to example studies below:

- Golden Spread Electric Cooperative (GSEC) Mustang Station - DE-FE0031844[1]
- Panda Power Funds Sherman Energy Center - DE-FE0031848[2]

Source Files:

1. *US DOE – NETL. Project Landing Page, Source: https://netl.doe.gov/project-information?p=FE0031844 accessed 12/6/22*
2. *US DOE – NETL. Project Landing Page, Source: https://netl.doe.gov/project-information?p=FE0031848 accessed 12/6/22*

Attachments: *None*

Co-Respondent(s): R. Cejas Goyannes, S. Narayan

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.6c
Respondent:	L. Mikulan
Page:	1 of 1

Question: Refer to the discussion of carbon capture and sequestration ("CCS") found on page 23, lines 4 – 14 of Ms. Mikulan's direct testimony.

c. Identify any coal- or gas-fired electric generating unit with CCS that has captured and sequestered at least 50% of the carbon that it would otherwise emit over a period of at least twelve months.

Answer: Per the Department of Energy's Regional Carbon Sequestration Partnership (RCSP) Initiative, there are several large-scale CO_2 tests (tests injecting at least 1 million metric tons of CO_2) currently being conducted or recently finished in the United States.

Example Projects:

- Citronelle Project (SECARB) (Alabama)[1]
- Illinois Basin Decatur CO2 Project (MGSC)(Illinois)[2]
    - Sequestration of biofuel production emissions in formations similar to those found throughout the state of Michigan

Source Files:

1. *US Department of Energy and National Energy Technology Laboratory, 2018. Citronelle Project, Source: https://www.netl.doe.gov/sites/default/files/2018-11/Citronelle-SECARB-Project.PDF accessed 12/6/22*
2. *US Department of Energy and National Energy Technology Laboratory, 2018. Illinois Basin-Decatur Project. Source: https://www.netl.doe.gov/sites/default/files/2018-11/Illinois-Basin-Decatur-Project.pdf accessed 12/6/22*

Department of Energy. Carbon Storage FAQs, Source: https://www.netl.doe.gov/carbon-management/carbon-storage/faqs/carbon-storage-faqs#doe accessed 12/6/22

Attachments: None

Co-Respondent(s): S. Narayan

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.6d
Respondent:	L. Mikulan
Page:	1 of 1

Question: Refer to the discussion of carbon capture and sequestration ("CCS") found on page 23, lines 4 – 14 of Ms. Mikulan's direct testimony.

d. Identify in dollars per ton the cost assumed in your modeling for capturing and sequestering the carbon that would otherwise be emitted by the CCGT plant.

Answer: The cost of capturing the carbon that would otherwise be emitted by the CCGT plant is a component of the resource's capital, efficiency (heat rate) and O&M and not provided in terms of dollars per ton. The capital costs of the CCGT plant with CCS can be found in "WP-RCG 5 EPRI Data". The sequestering of the carbon is $11.95 per metric ton (2023).

Attachments: *None.*

Co-Respondent(s): S. Manning,R. Cejas Goyannes

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.6e
Respondent:	L. Mikulan
Page:	1 of 1

Question: Refer to the discussion of carbon capture and sequestration ("CCS") found on page 23, lines 4 – 14 of Ms. Mikulan's direct testimony.

e. Identify any sites where you anticipate the carbon captured at the CCGT with CCS plant could be sequestered.

Answer: Studies by the Department of Energy (DOE)/National Energy Technology laboratory (NETL) highlight the presence of the Sylvania Sandstone, St. Peter Sandstone, and Mount Simon Formation throughout the state of Michigan. DTE Electric anticipates the siting of sequestration that both targets these storage formations while remaining proximal to the capture source.

Per the DOE's Midwest Regional Carbon Sequestration Partnership (MRCSP), the largest potential sequestration capacity in the Midwest occurs in the state of Michigan. Almost all of this capacity is in deep saline formations that include the Sylvania Sandstone, St. Peter Sandstone, and Mount Simon Formation.

US DOE – NETL. Carbon Storage Atlas, Source: https://netl.doe.gov/coal/carbon-storage/atlas/mrcsp/phase-I accessed 12/6/22

Attachments: None

Co-Respondent(s): S. Narayan

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.7a
Respondent:	L. Mikulan
Page:	1 of 1

Question: Refer to Figure 2 on page 24 of the direct testimony of Ms. Mikulan.

a. Identify and produce the source for Figure 2.

Answer: The source is "Emerging Generation Technologies Road-Mapping Study" by Black and Veatch, page 1-8, submitted as WP LKM-1.

Attachments: None

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.7b
Respondent:	L. Mikulan
Page:	1 of 1

Question: Refer to Figure 2 on page 24 of the direct testimony of Ms. Mikulan.

b. Explain the difference between the “1st Gen” and “2nd Gen” carbon capture referenced in Figure 2.

Answer: Please refer to page 1-6 in “Emerging Generation Technologies Road-Mapping Study” by Black and Veatch, submitted as WP LKM-1.

Attachments: None

MPSC Case No.:	U-21193
Requestor:	MNSC
Question No.:	MNSCDE-1.8
Respondent:	S. Roy
Page:	1 of 1

Question: Please provide the NERC steady-state model validation reports (MOD-025) for all units at the Belle River and Monroe power plants.

Answer: DTE Electric objects to the request for the reasons that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm, seeks information involving Cyber Security, CEII (either critical energy infrastructure information or critical electric infrastructure information), North American Electric Reliability Corporation (NERC) NERC-CIP (including but not limited to BES Cyber Asset information subject to protection under the Information Protection Program pursuant to NERC Reliability Standards CIP-003-6 and CIP-011-2), Supervisory Control and Data Acquisition (SCADA), confidential Midcontinent Independent System Operation (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric, U.S. export control laws and regulations, including but not limited to 10 C.F.R. Part 810 *et. seq*., or 10 CFR Part 2.390 and is otherwise not reasonably calculated to lead to the discovery of admissible evidence.

Attachments: None

Co-Respondent(s): Legal

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of DTE ELECTRIC COMPANY for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief	))))	Case No. U-21193

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on December 13, 2022, she served a copy of DTE Electric Company's response to the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan First Discovery Request in the above captioned matter, via electronic mail and portal link, upon the persons listed on the attached service list.

Estella R. Branson
Digitally signed by Estella R. Branson
Date: 2022.12.13 10:38:49 -05'00'

ESTELLA R. BRANSON

MPSC Case No. U-21193
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MPSC Case No. U-21193
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NETL's Updated Performance and Cost Estimates for Power Generation Facilities Equipped with Carbon Capture

NATIONAL ENERGY TECHNOLOGY LABORATORY

Marc Turner
NETL site support contractor

Purpose of Study

- Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity – Revision 4a
  - Published October 2022, available at https://www.osti.gov/biblio/1893822
- Generate an independent, public assessment of the cost and performance of select, state-of-the-art, fossil-fueled power-generation systems with and without CO_2 capture using a systematic, transparent, technical and economic approach
  - Primarily used for research and development (R&D) guidance and evaluation
  - Increasingly used directly by various organizations for system modeling efforts
  - Provides state-of-the-art reference data for regulators and policy makers

Limitations of Study Data

- Real projects will have a variety of location-specific factors that affect costs and require more extensive analysis and study (e.g., front-end engineering design (FEED) studies) to reduce uncertainty
  - Recently completed NETL funded FEED studies on CO_2 capture retrofits of natural gas power plants:
    - Bechtel (March 2022), available at https://www.osti.gov/biblio/1836563
    - Southern Company (September 2022), available at https://www.osti.gov/biblio/1890156
- Initial deployments of plants that include technologies that are not yet fully mature may incur costs higher than those reflected within this report (e.g., plants with Carbon Capture)

Overview

- Revision 4a
  - Incorporates recent (2021) post-combustion capture system performance and cost data from Shell CANSOLV
    - Revises 90 percent capture cases for pulverized coal (PC) and natural gas combined cycle (NGCC) plants
    - Adds higher capture rate cases to PC and NGCC plants
  - Adds H-class NGCC cases with and without capture
  - Includes miscellaneous minor updates to the cost and performance models

Study Assumptions

- Design basis is consistent with Revision 4 assumptions, including:
  - Location – Generic Midwest site with International Organization for Standardization (ISO) ambient conditions
  - Applicable air and water regulations
  - 2018-dollar basis
  - Capacity Factors: PC and NGCC – 85%
  - Capital cost estimation methodology,[1] fuel compositions,[2,3] fuel costs,[4] and CO_2 transport and storage (T&S) prices[5]
    - Fuel Costs:
      - Natural Gas – \$4.19/GJ (\$4.42/MMBtu), on a higher heating value (HHV) basis
      - Illinois No. 6 Coal – \$2.11/GJ (\$2.23/MMBtu), on an HHV basis
    - T&S Costs – \$10 per tonne (\$9/ton) of CO_2

[1] NETL, "Quality Guidelines for Energy System Studies (QGESS): Cost Estimation Methodology for NETL Assessments of Power Plant Performance," U.S. Department of Energy, Pittsburgh, PA, 2019. https://www.osti.gov/biblio/1567736
[2] NETL, "QGESS: Detailed Coal Specifications," U.S. Department of Energy, Pittsburgh, PA, 2019. https://www.osti.gov/biblio/1567737
[3] NETL, "QGESS: Specification for Selected Feedstocks," U.S. Department of Energy, Pittsburgh, PA, 2019. https://www.osti.gov/biblio/1557271
[4] NETL, "QGESS: Fuel Prices for Selected Feedstocks in NETL Studies," U.S. Department of Energy, Pittsburgh, PA, 2019. https://www.osti.gov/biblio/1557270
[5] NETL, "QGESS: Carbon Dioxide Transport and Storage Costs in NETL Studies," U.S. Department of Energy, Pittsburgh, PA, 2019. https://www.osti.gov/biblio/1567735

Cost Estimation Methodology[1]

NATIONAL ENERGY TECHNOLOGY LABORATORY

- Vendor-provided cost data for Shell's CANSOLV CO_2 capture system was adjusted for year dollar basis and scaled on capacity
- Vendor-provided cost data for H-class NGCC cases were adjusted for year dollar basis and consistency with F-class cost estimating methodology
- Balance of plant capital cost estimates for Revision 4a were scaled from those in the 2019 Revision 4 report using the methodology established in the relevant NETL QGESS[2] documents
- American Association of Cost Engineers (AACE) Class 4 estimate with an uncertainty range of -15/+30% for PC cases and -15/+25% for NGCC cases

[1] NETL, "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance," U.S. Department of Energy, Pittsburgh, PA, 2019. https://www.osti.gov/biblio/1567736
[2] NETL, "QGESS: Capital Cost Scaling Methodology," U.S. Department of Energy, Pittsburgh, PA, 2019. https://www.osti.gov/biblio/1893821

PC and NGCC Case Configuration Summary

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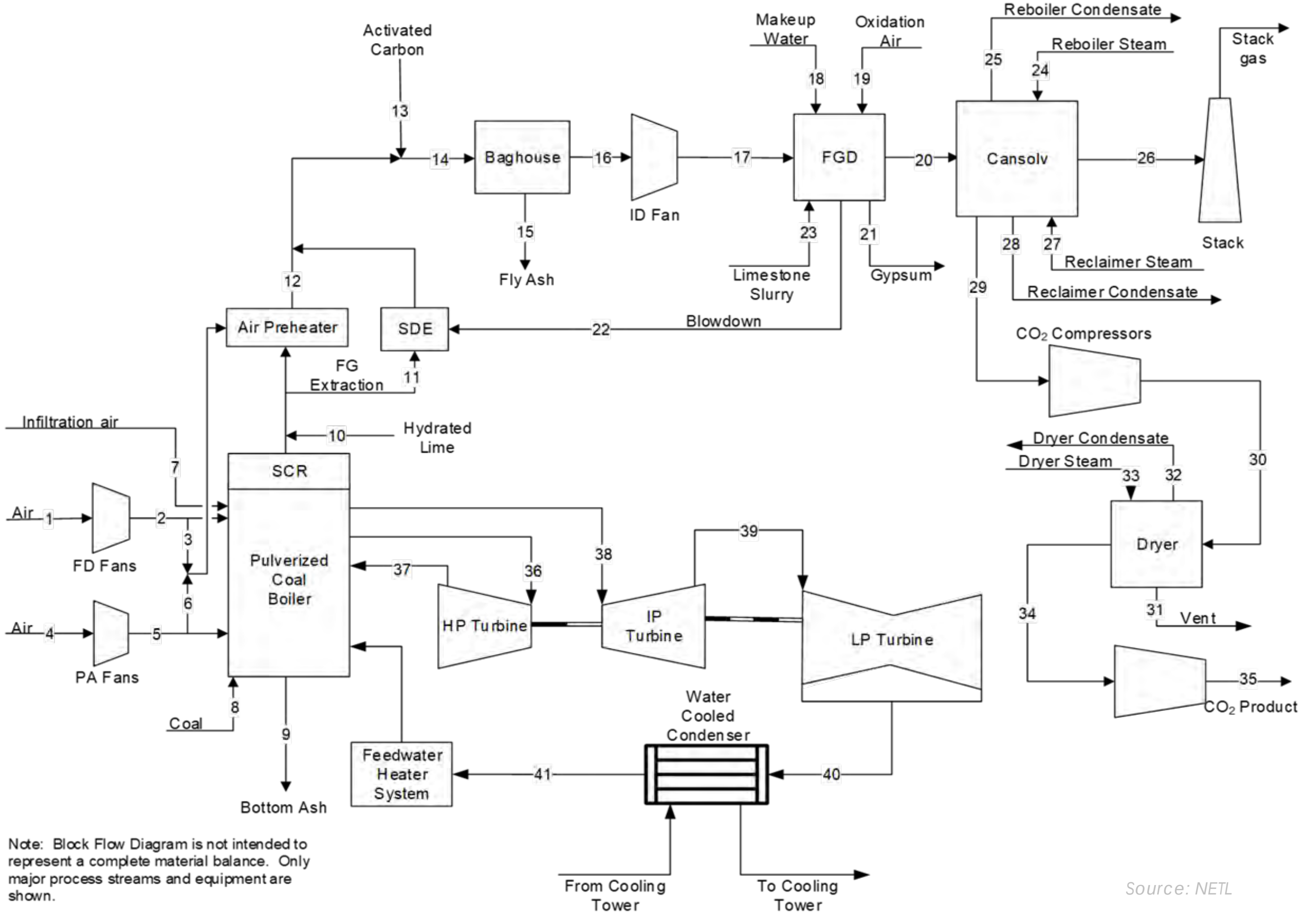
<table>
<tr><th>Case</th><th>Plant Type</th><th>Steam Cycle, psig/°F/°F</th><th>Combustion Turbine</th><th>Gasifier/Boiler Technology</th><th>Sulfur Removal</th><th>Particulate Matter Control</th><th>CO_2 Separation</th><th>Capture Rate</th><th>Process Water Treatment</th></tr>
<tr><td>B11A</td><td rowspan="8">PC</td><td rowspan="4">2400/1050/1050</td><td rowspan="8">N/A</td><td rowspan="4">Subcritical (SubC) PC</td><td rowspan="8">Wet Flue Gas Desulfurization/ Gypsum</td><td rowspan="8">Baghouse</td><td>N/A</td><td>N/A</td><td rowspan="8">Spray Dryer Evaporator</td></tr>
<tr><td>B11B.90</td><td rowspan="3">CANSOLV</td><td>90%</td></tr>
<tr><td>B11B.95</td><td>95%</td></tr>
<tr><td>B11B.99</td><td>99%</td></tr>
<tr><td>B12A</td><td rowspan="4">3500/1100/1100</td><td rowspan="4">Supercritical (SC) PC</td><td>N/A</td><td>N/A</td></tr>
<tr><td>B12B.90</td><td rowspan="3">CANSOLV</td><td>90%</td></tr>
<tr><td>B12B.95</td><td>95%</td></tr>
<tr><td>B12B.99</td><td>99%</td></tr>
<tr><td>B31A</td><td rowspan="8">NGCC</td><td rowspan="4">2378/1085/1084</td><td rowspan="4">2 x State-of-the-art 2017 F-Class</td><td rowspan="8">HRSG</td><td rowspan="8">N/A</td><td rowspan="8">N/A</td><td>N/A</td><td>N/A</td><td rowspan="8">N/A</td></tr>
<tr><td>B31B.90</td><td rowspan="3">CANSOLV</td><td>90%</td></tr>
<tr><td>B31B.95</td><td>95%</td></tr>
<tr><td>B31B.97</td><td>97%</td></tr>
<tr><td>B32A</td><td rowspan="4">2668/1085/1044</td><td rowspan="4">2 x State-of-the-art 2017 H-Class</td><td>N/A</td><td>N/A</td></tr>
<tr><td>B32B.90</td><td rowspan="3">CANSOLV</td><td>90%</td></tr>
<tr><td>B32B.95</td><td>95%</td></tr>
<tr><td>B32B.97</td><td>97%</td></tr>
</table>

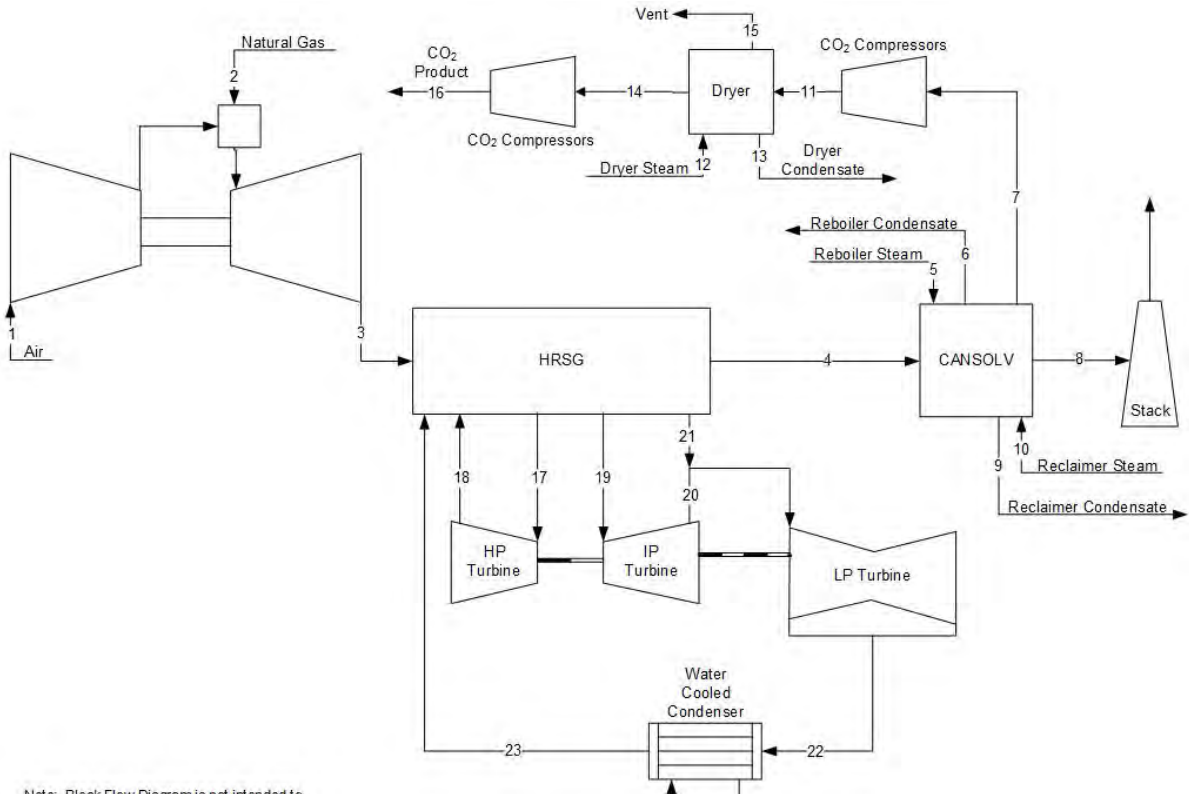
Block Flow Diagram – PC with CO_2 Capture



Source: NETL

ID = induced draft
FGD = flue gas desulfurization
SDE = spray dryer evaporator
FG = flue gas
SCR = selective catalytic reduction
FD = forced draft
PA = primary air
HP = high pressure
IP = intermediate pressure
LP = low pressure

Block Flow Diagram – NGCC with CO_2 Capture

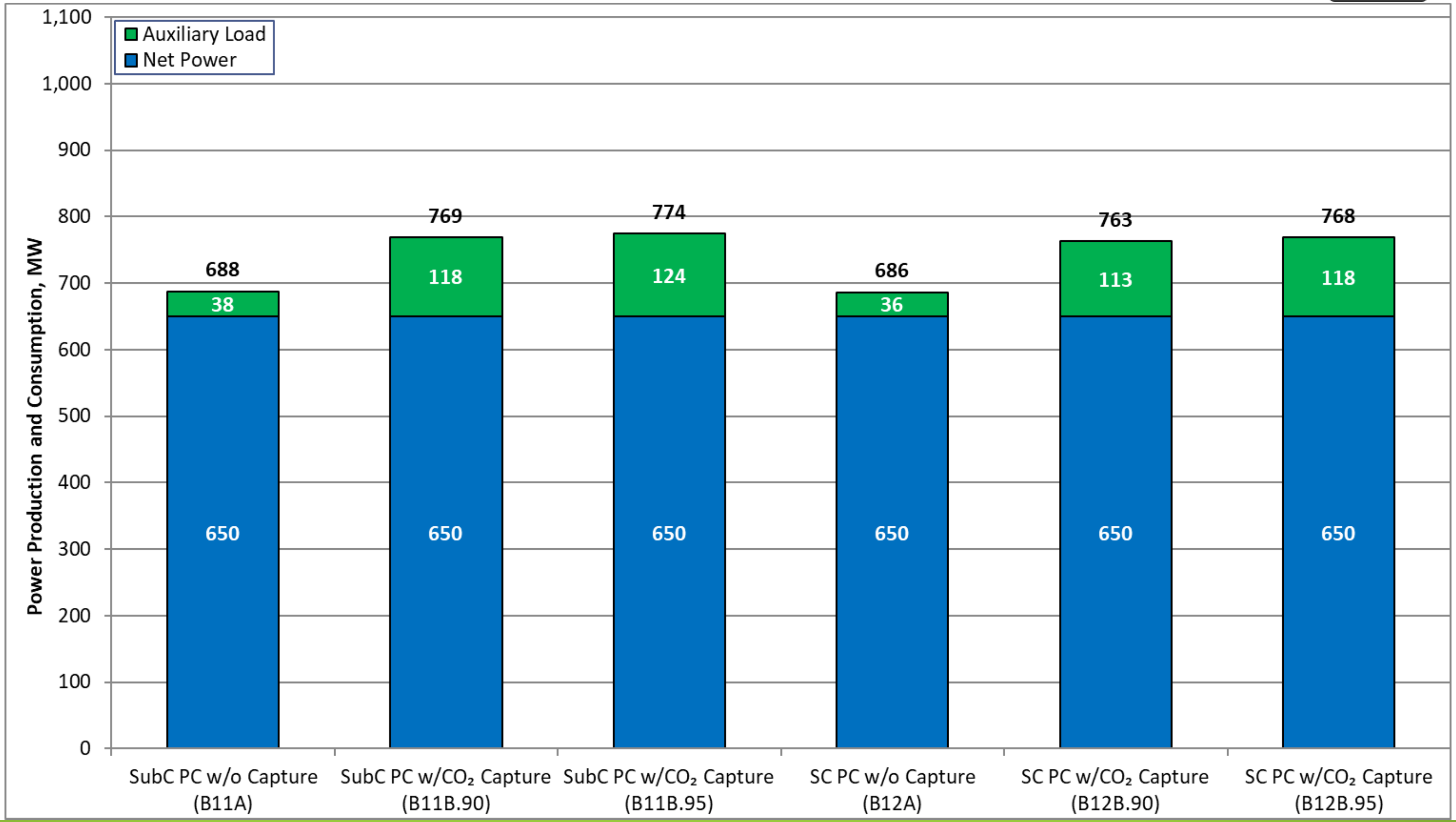


Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

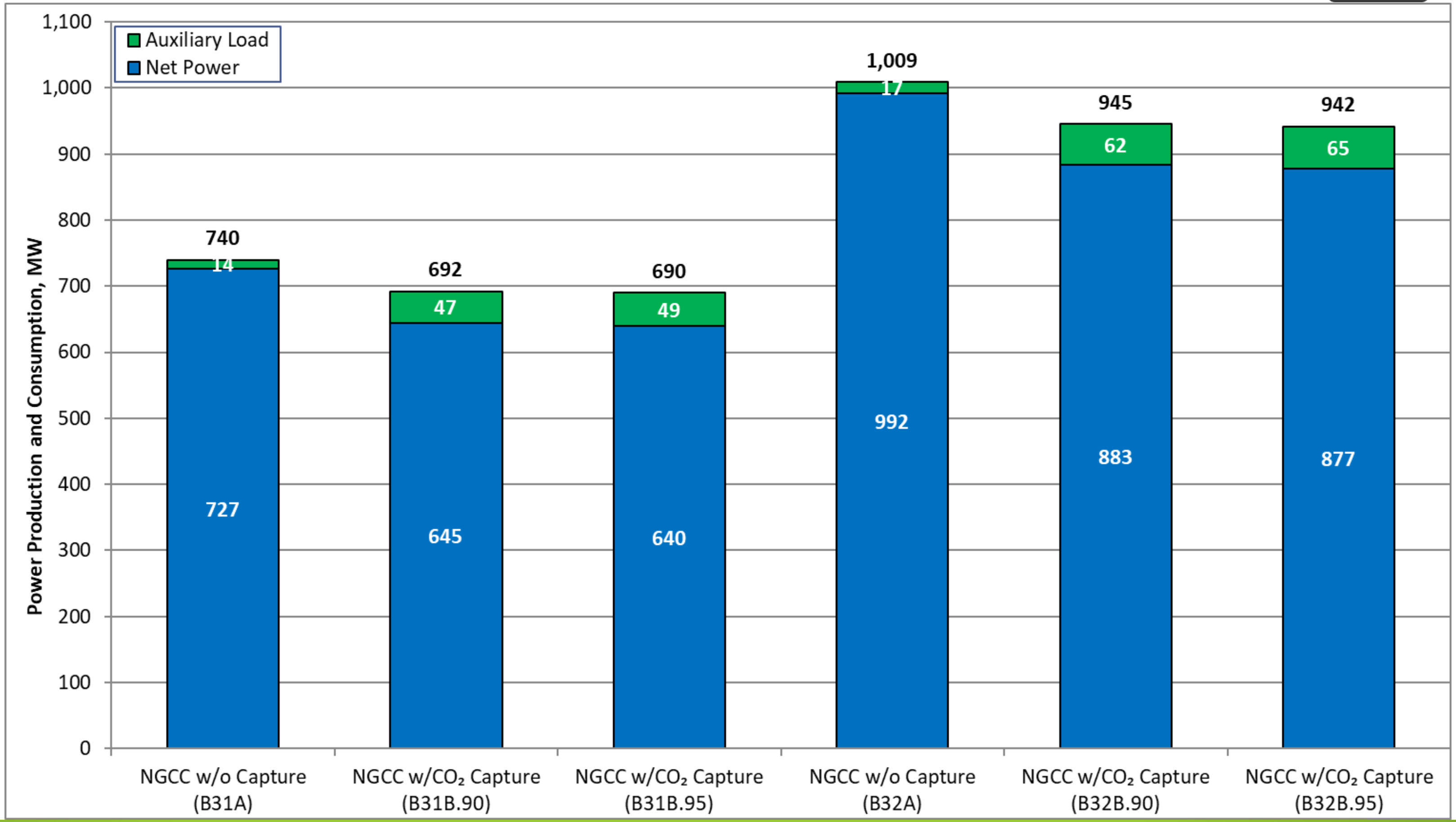
Source: NETL

HRSG = heat recovery steam generator

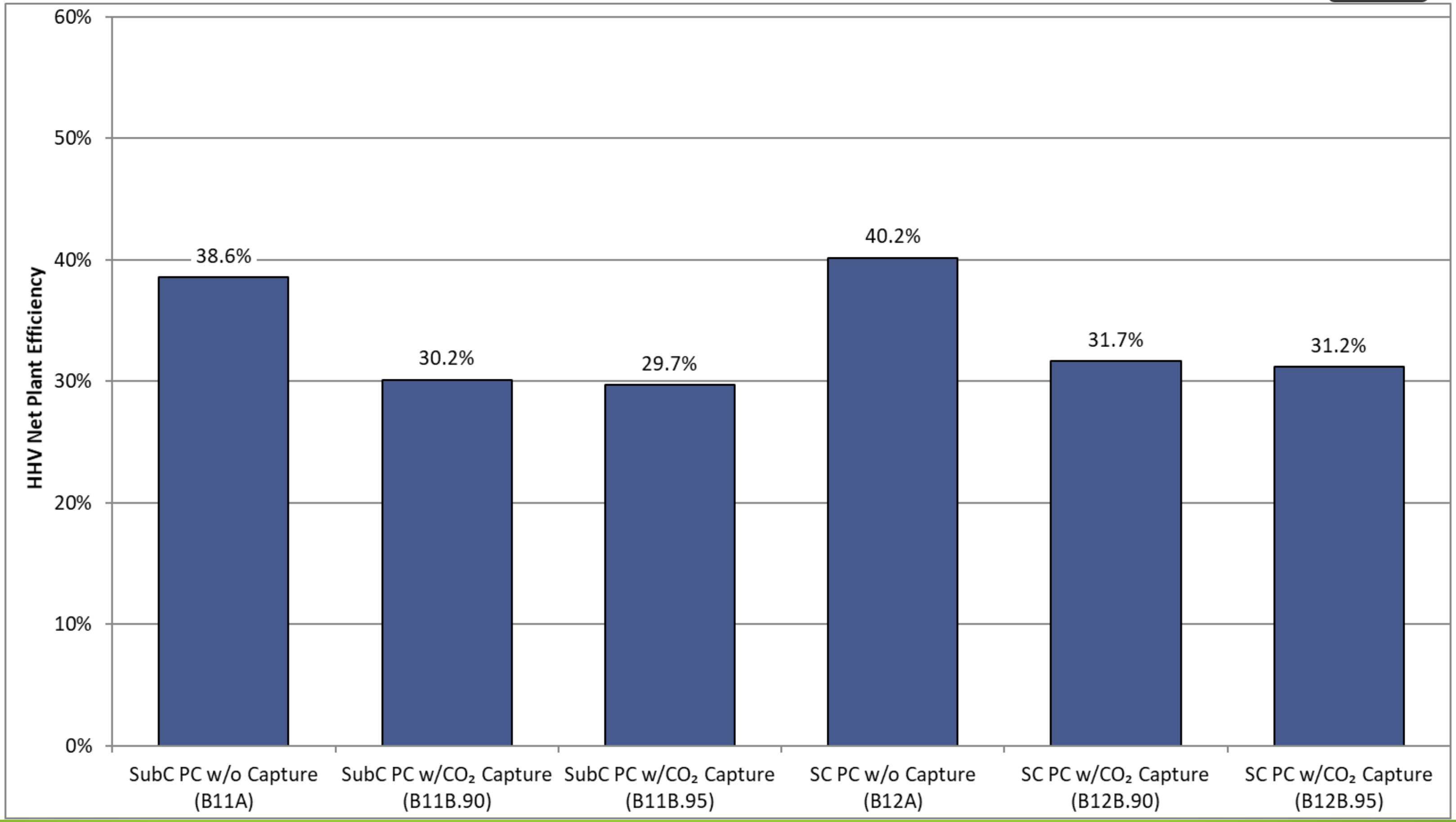
PC Power Summary



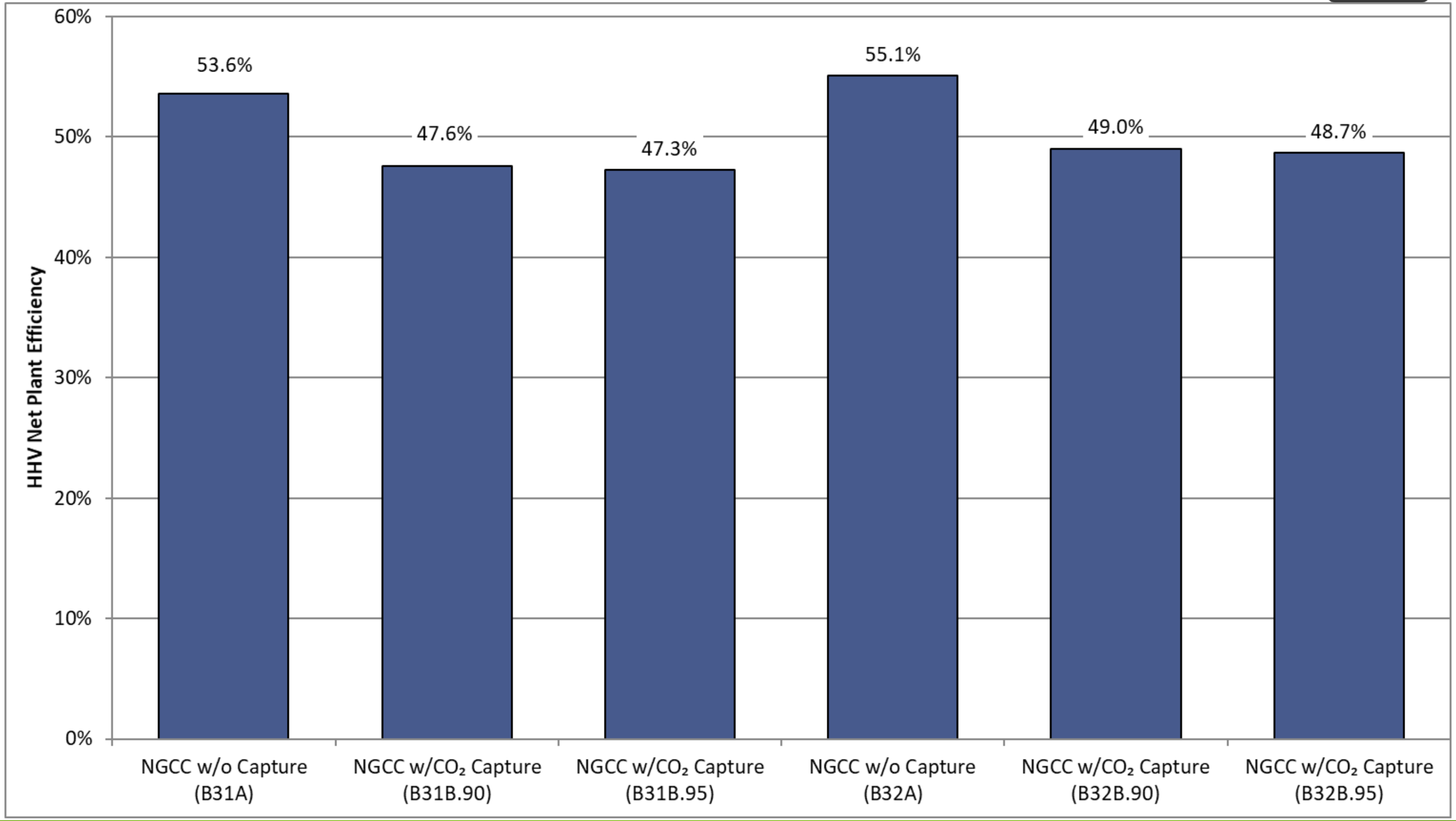
NGCC Power Summary



PC Net Plant Efficiency Summary



NGCC Net Plant Efficiency Summary



PC Water Summary

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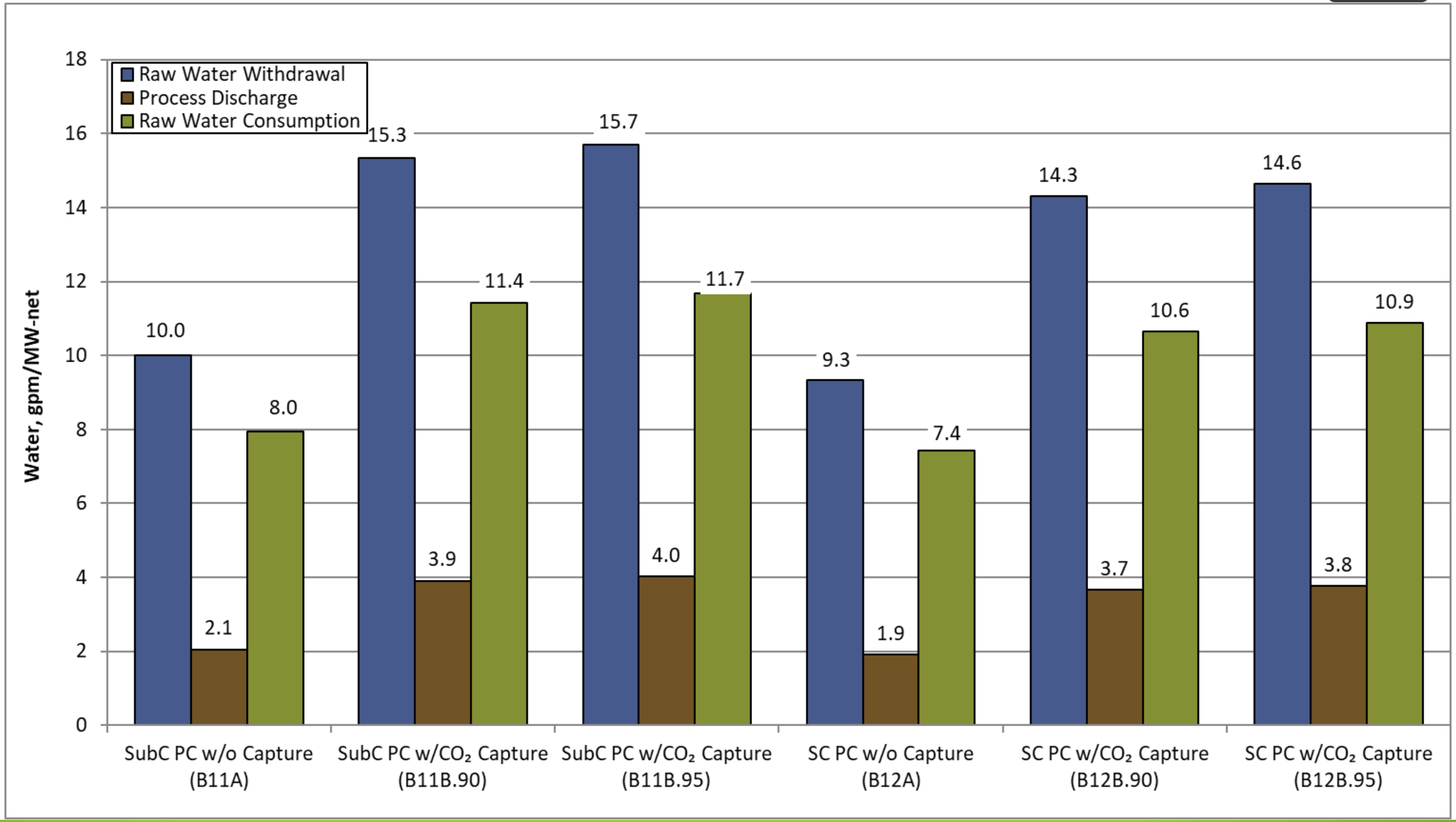
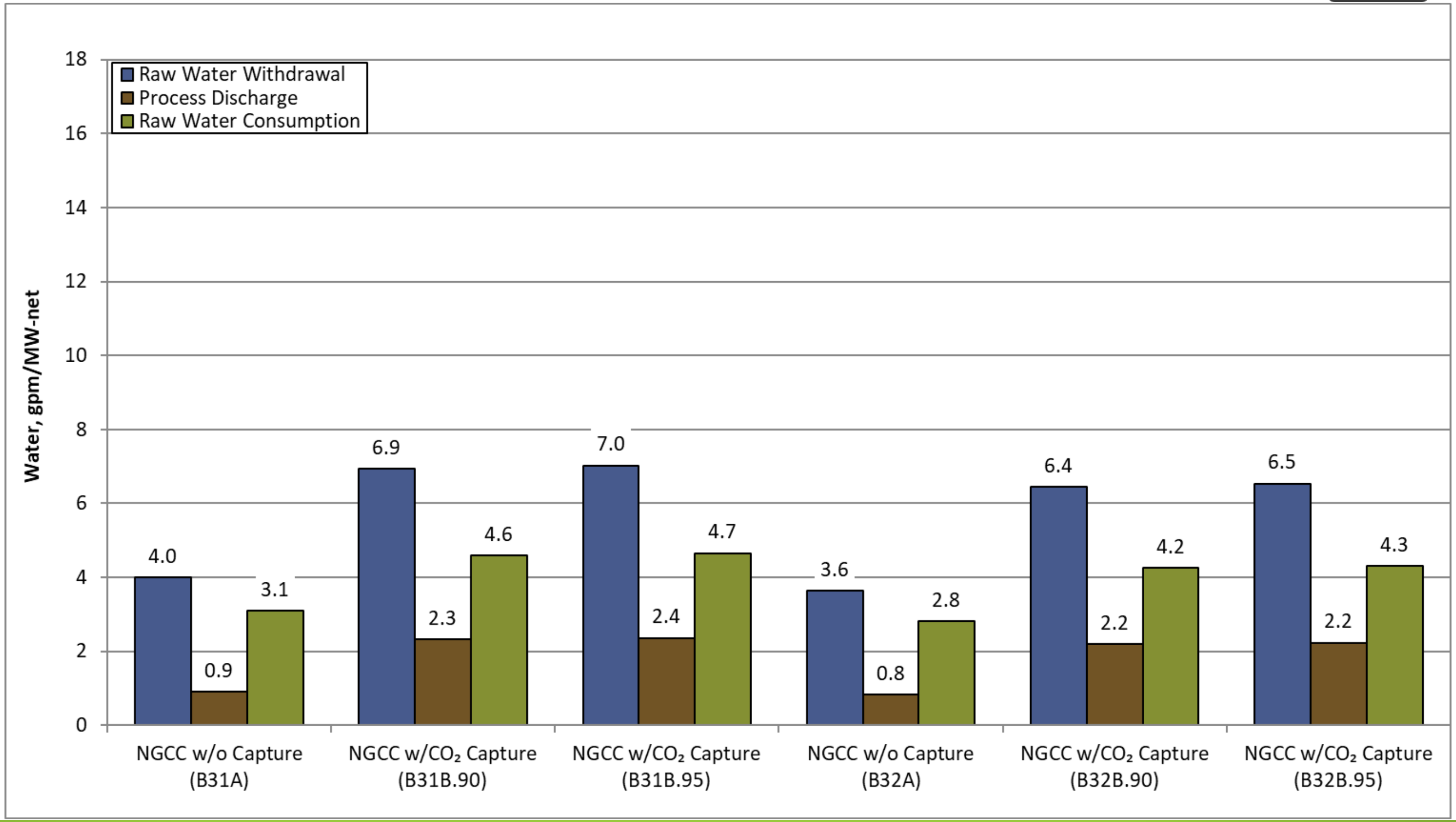


NGCC Water Summary



PC Capital Cost Summary

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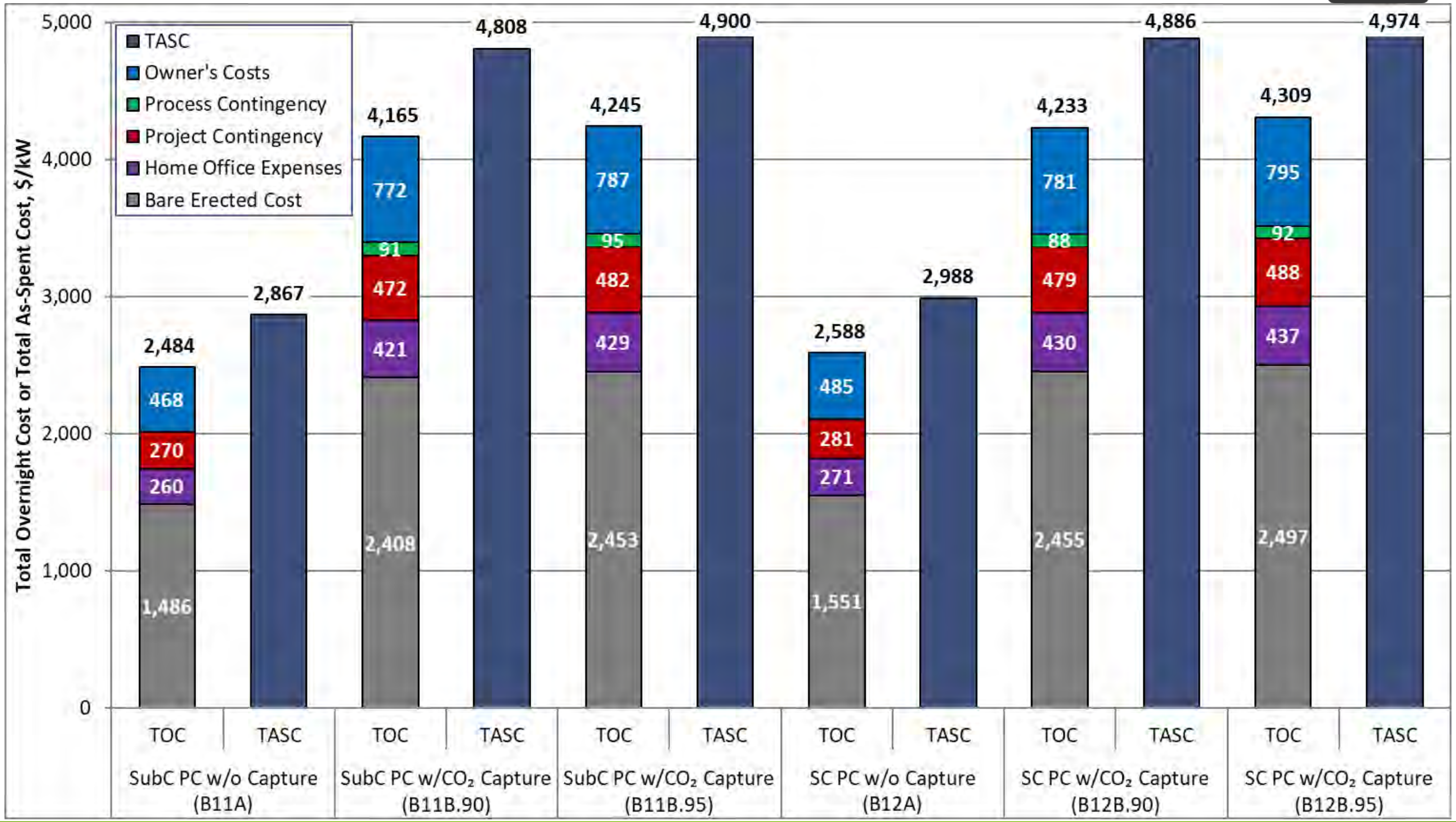
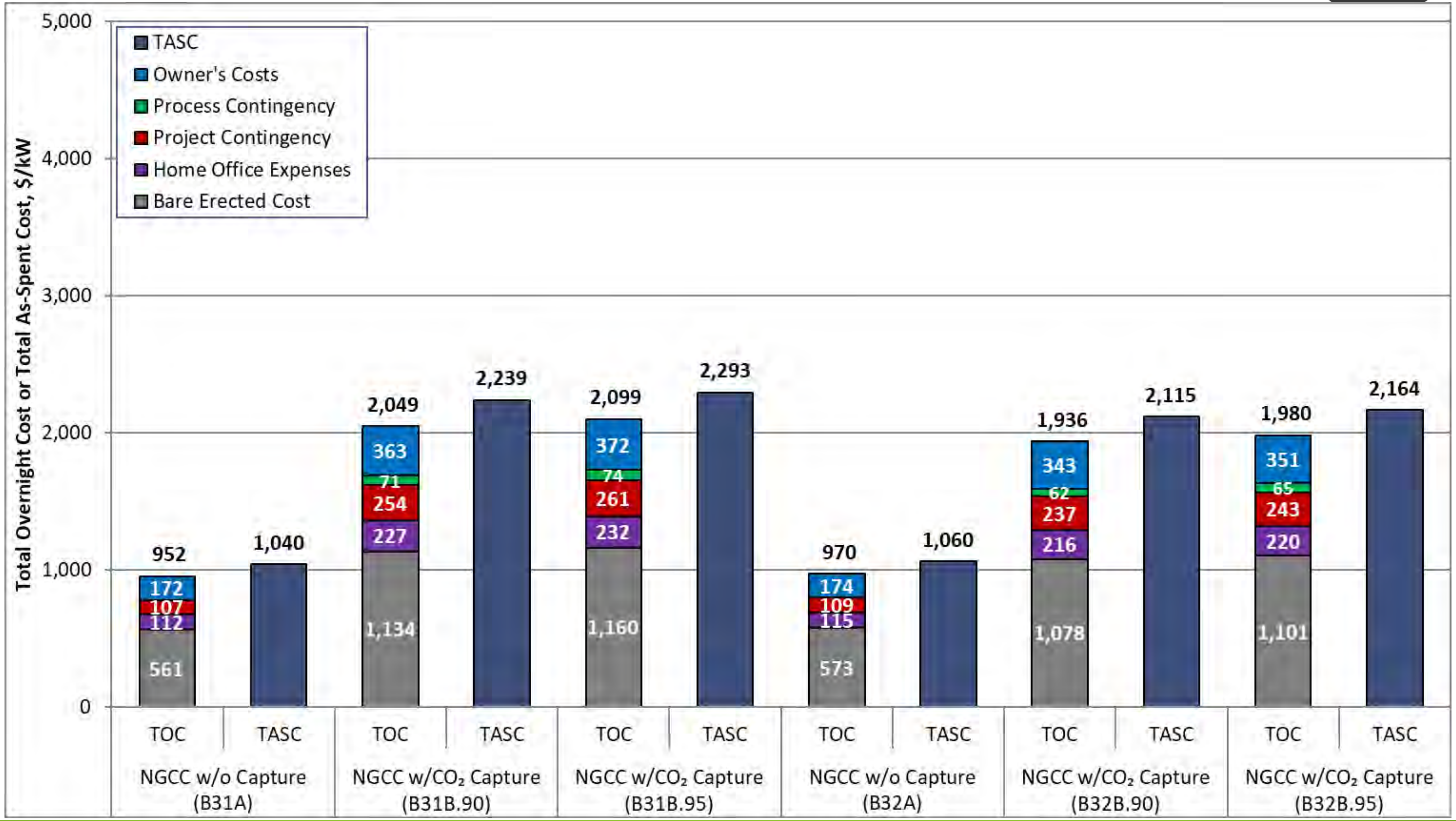


TOC = total overnight costs
TASC = total as-spent costs

U.S. DEPARTMENT OF ENERGY

NGCC Capital Cost Summary



PC LCOE Summary

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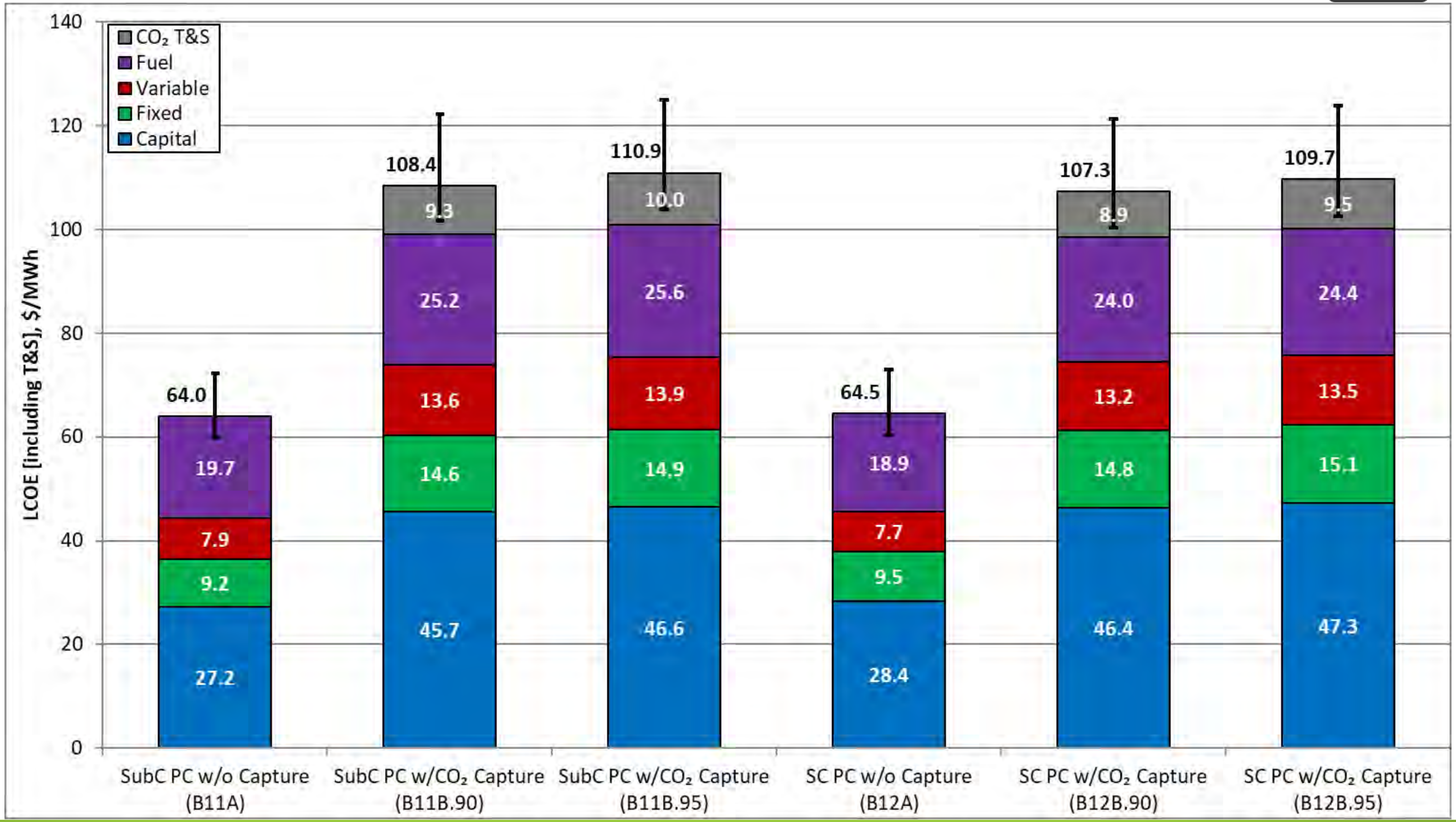

LCOE = levelized cost of electricity

NGCC LCOE Summary

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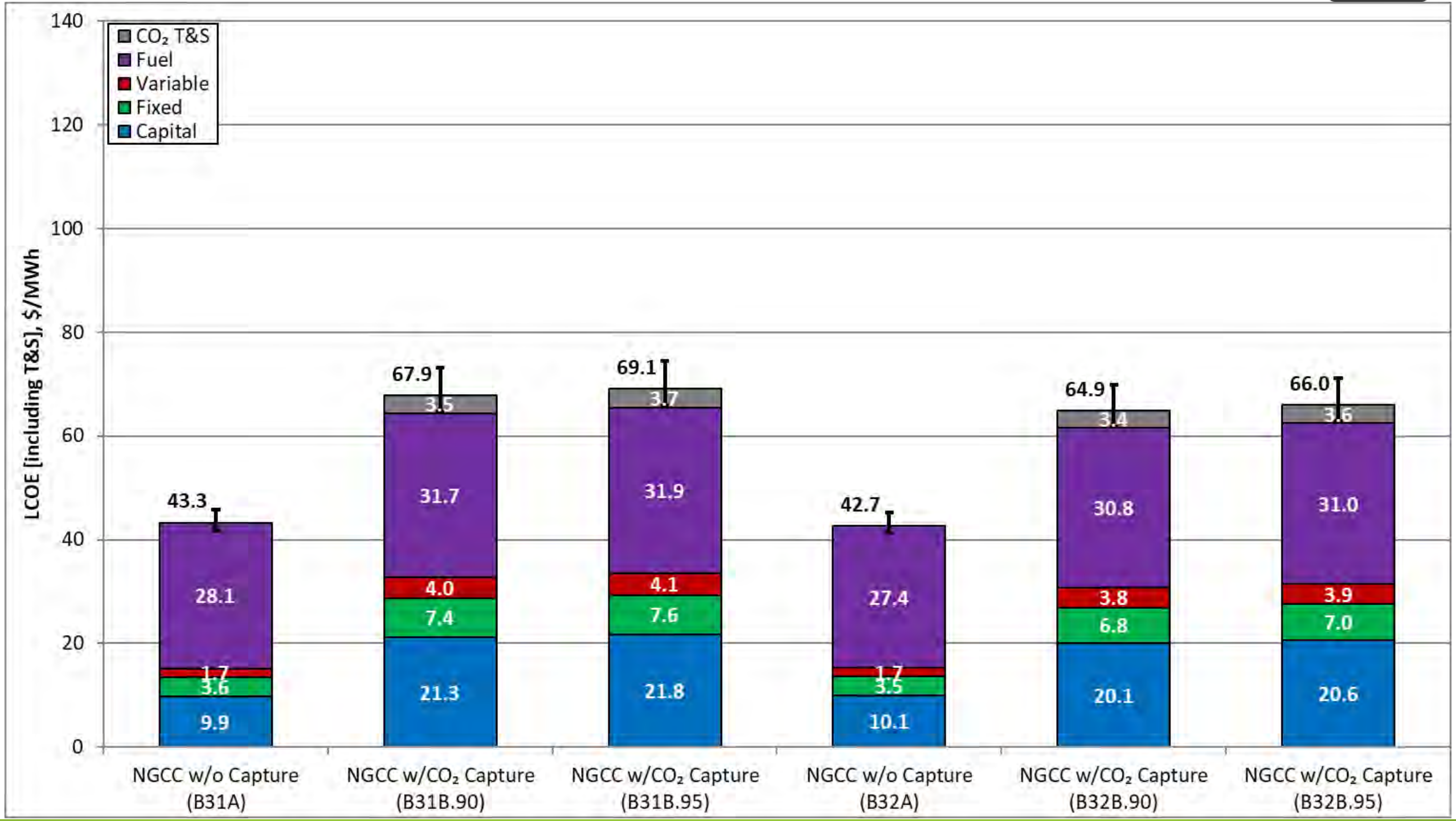

PC Cost of CO_2 Captured and Avoided

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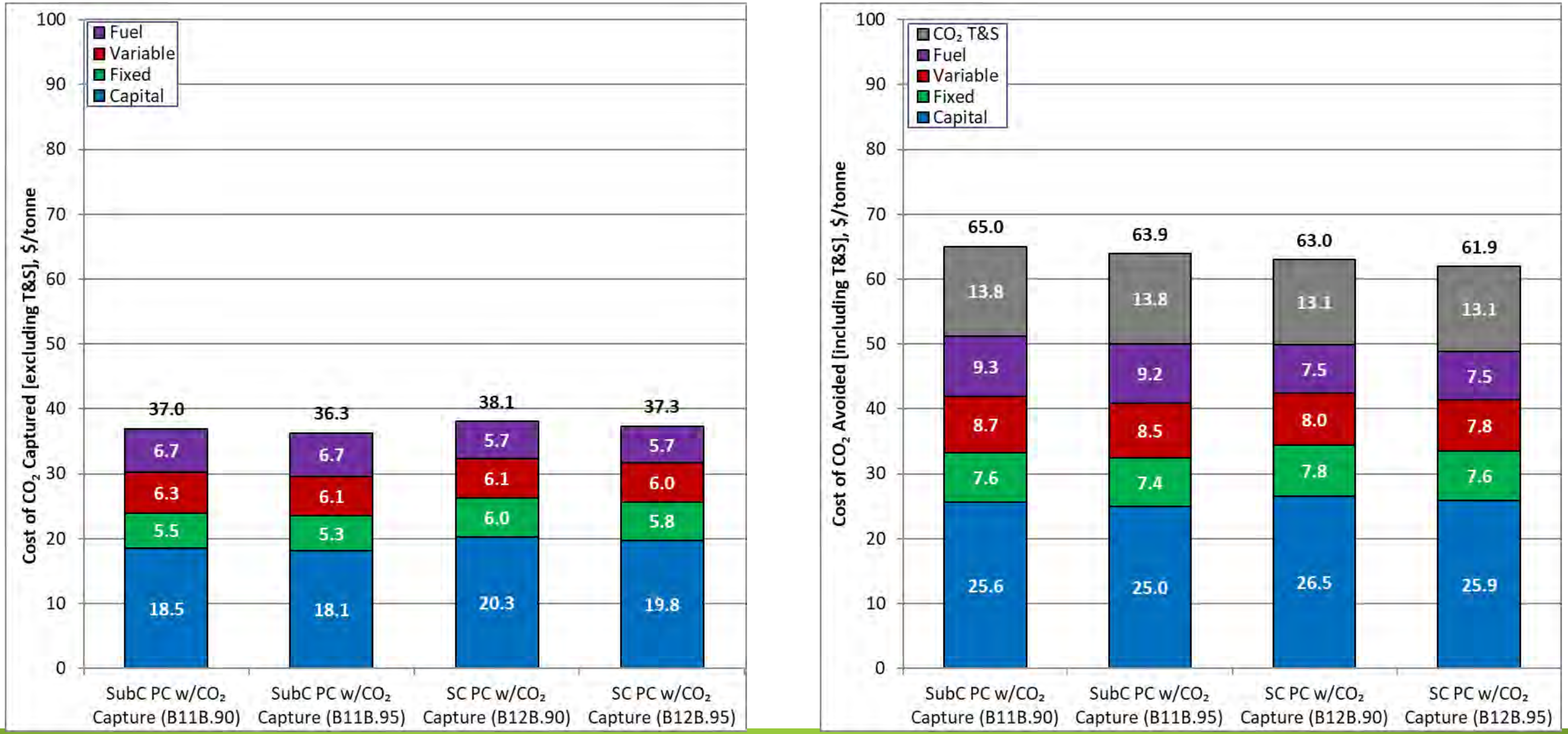
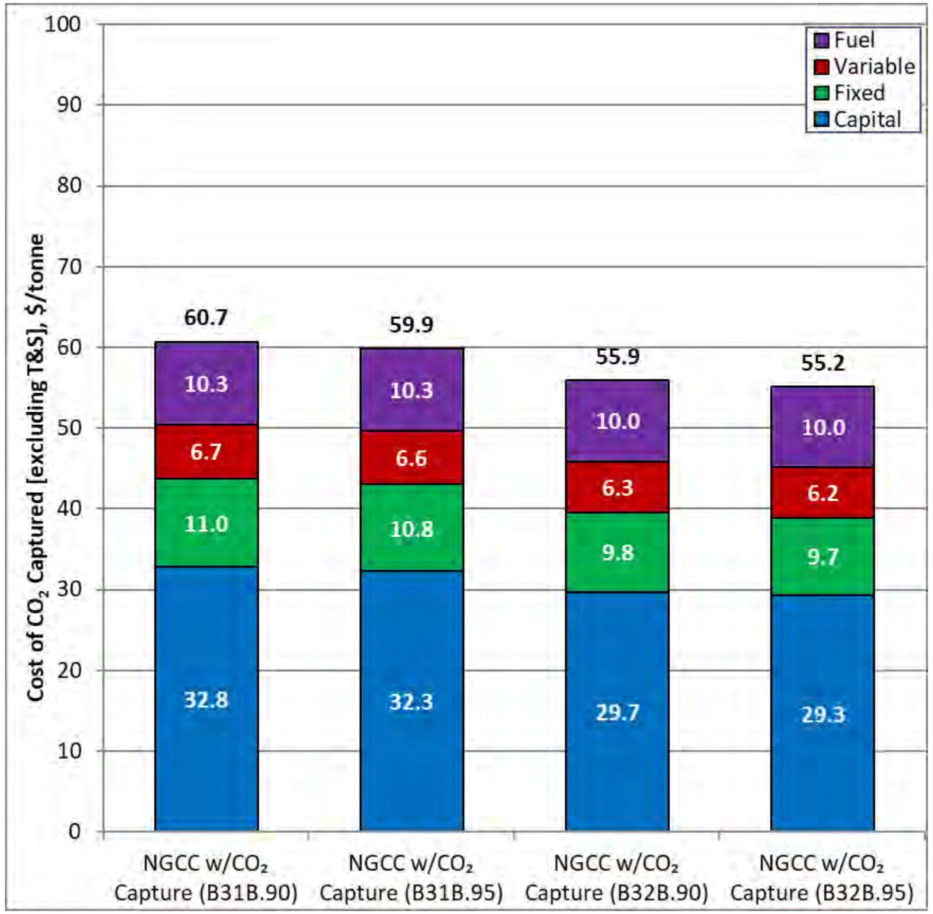
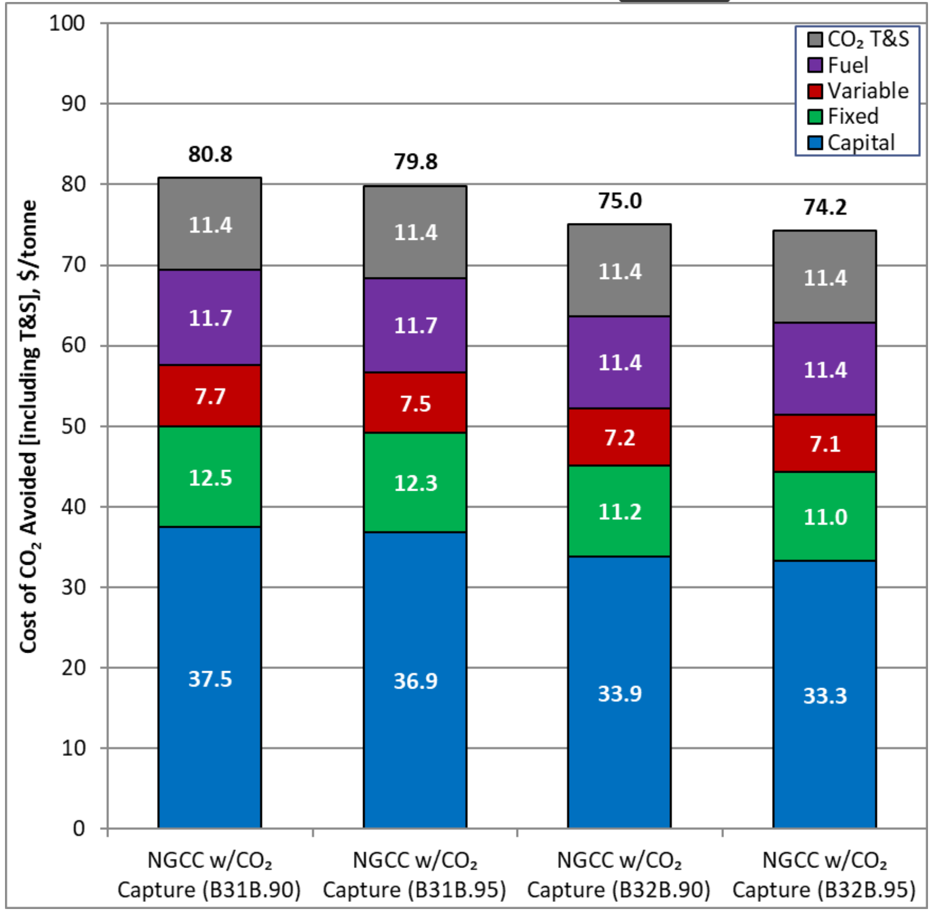


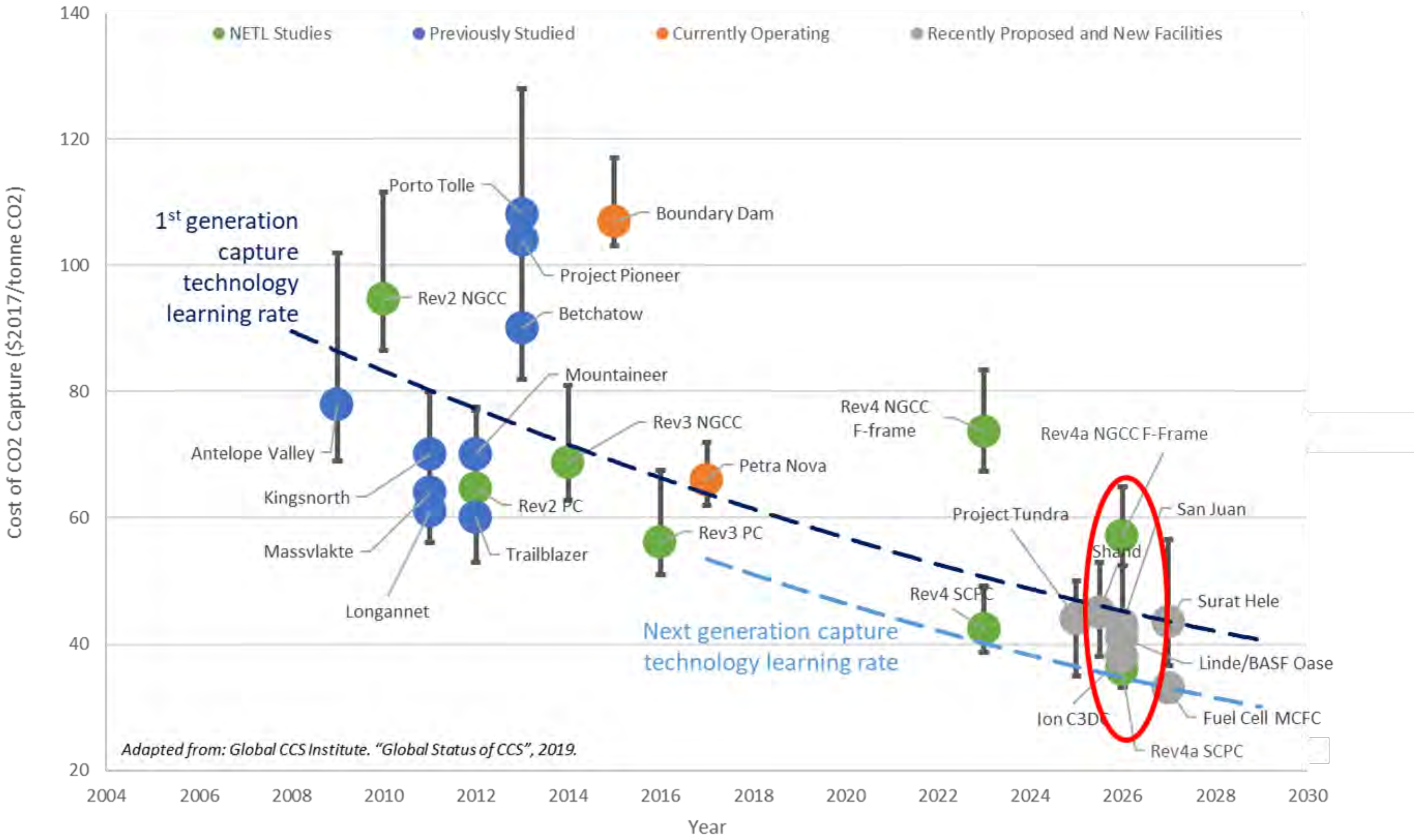
NGCC Cost of CO_2 Captured and Avoided

NATIONAL ENERGY TECHNOLOGY LABORATORY

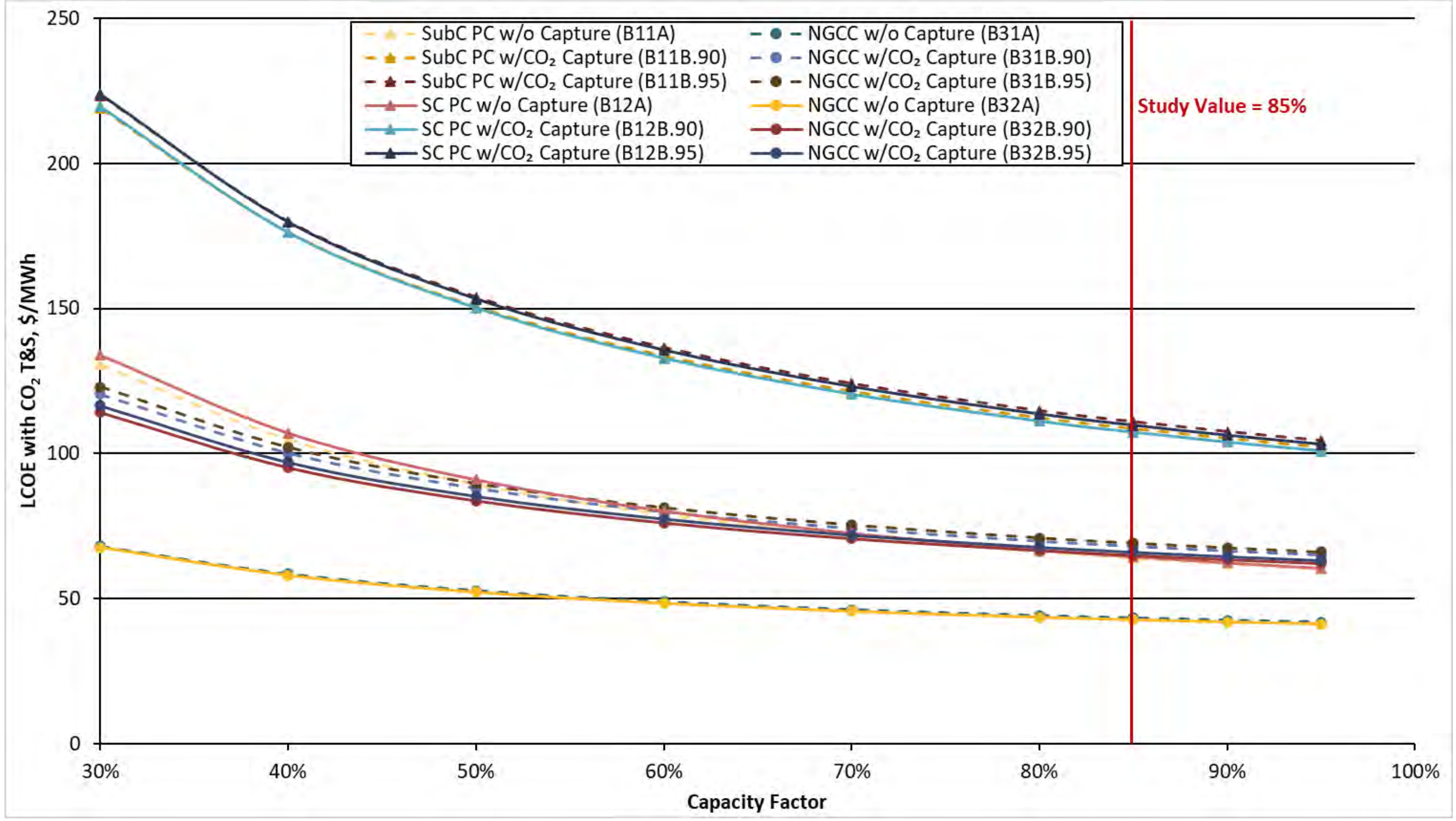




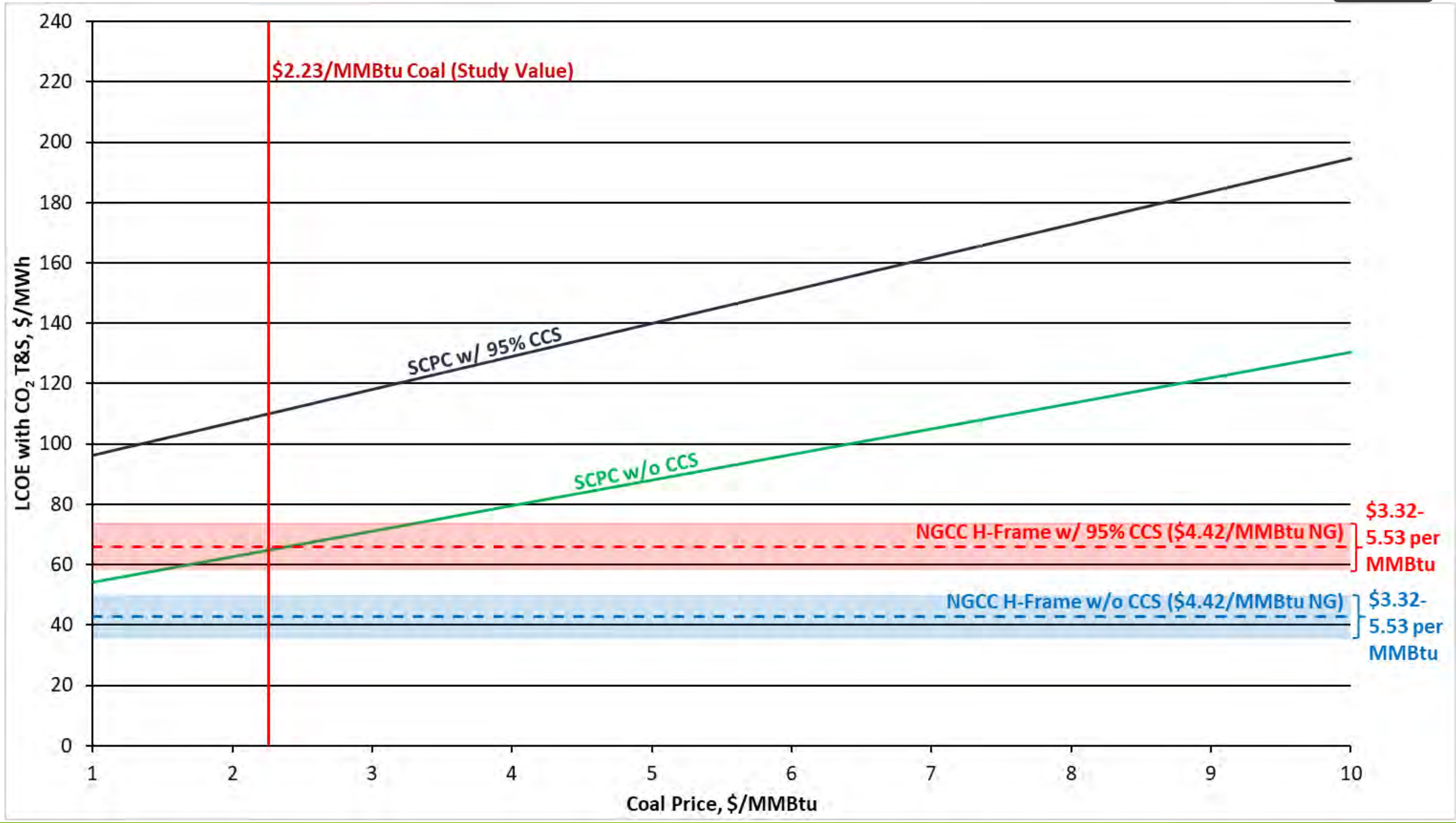
Revision 4a Estimates in Context



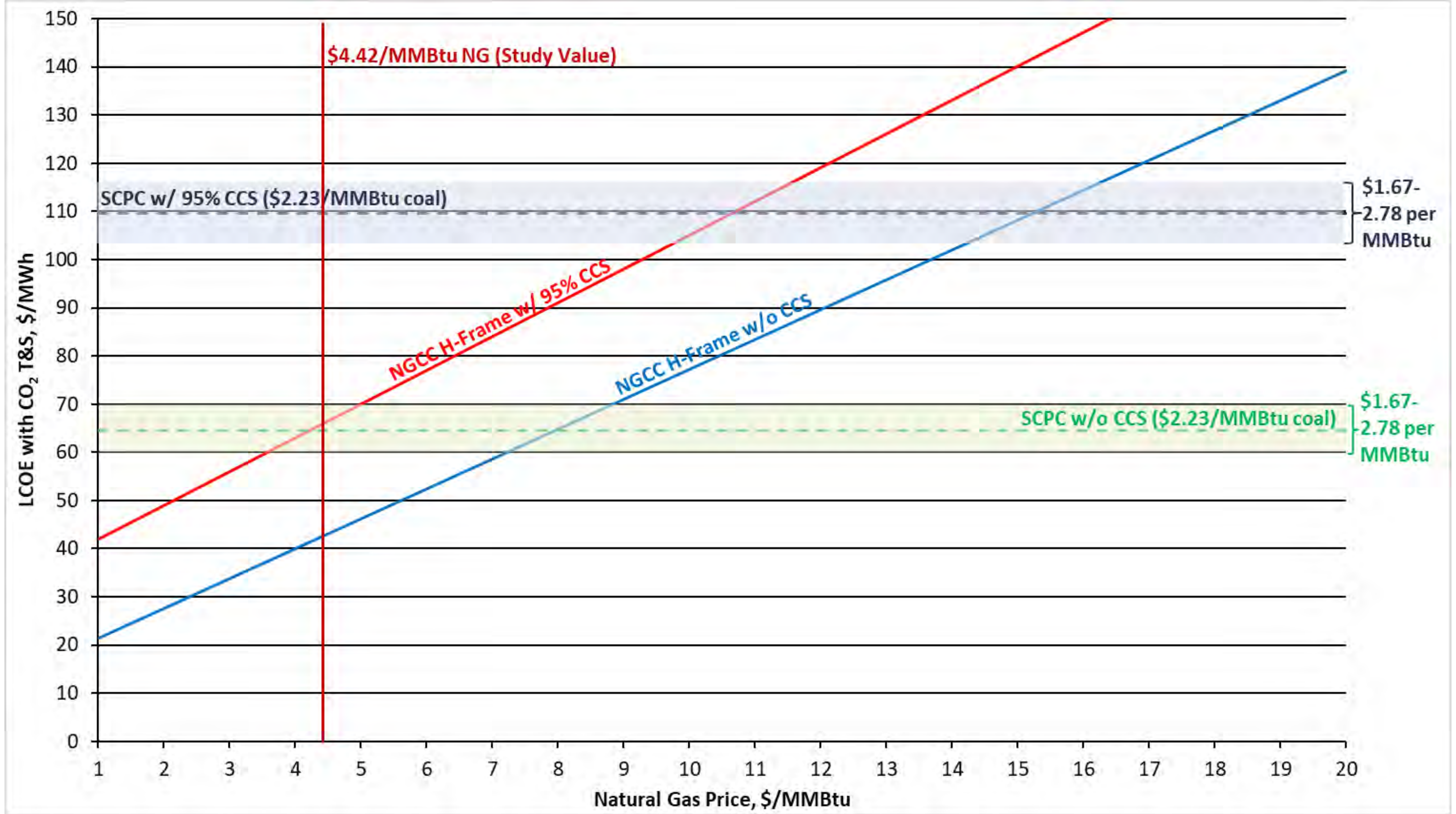
Sensitivity to Capacity Factor



Sensitivity to Coal Price



Sensitivity to Natural Gas Price



Distinction Between 95% Capture and Higher Rates

- Commercial-scale demonstration of solvent-based post-combustion CO_2 capture systems at power generation facilities (specifically PC plants) has shown the ability to capture 90% of the CO_2 in the flue gas stream
- Field-testing of post-combustion CO_2 capture technology, as well as vendor and industry feedback on projects currently in the planning stages, indicates that capture rates as high as 95% are feasible for both coal- and natural gas-fueled electricity generating units
- Technology suppliers and subject matter experts acknowledge and support that solvent-based, post-combustion CO_2 capture technologies can achieve CO_2 removal rates beyond 95% on low-purity streams representative of fossil-fueled combustion
- Although technoeconomic analyses of deep decarbonization (≥ 99%) of combustion flue gas have been published by others, the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study
- Technoeconomic analysis of the higher capture rates (97% NGCC and 99% PC) are included in the subject report

PC with 99% CO_2 Capture vs. No Capture

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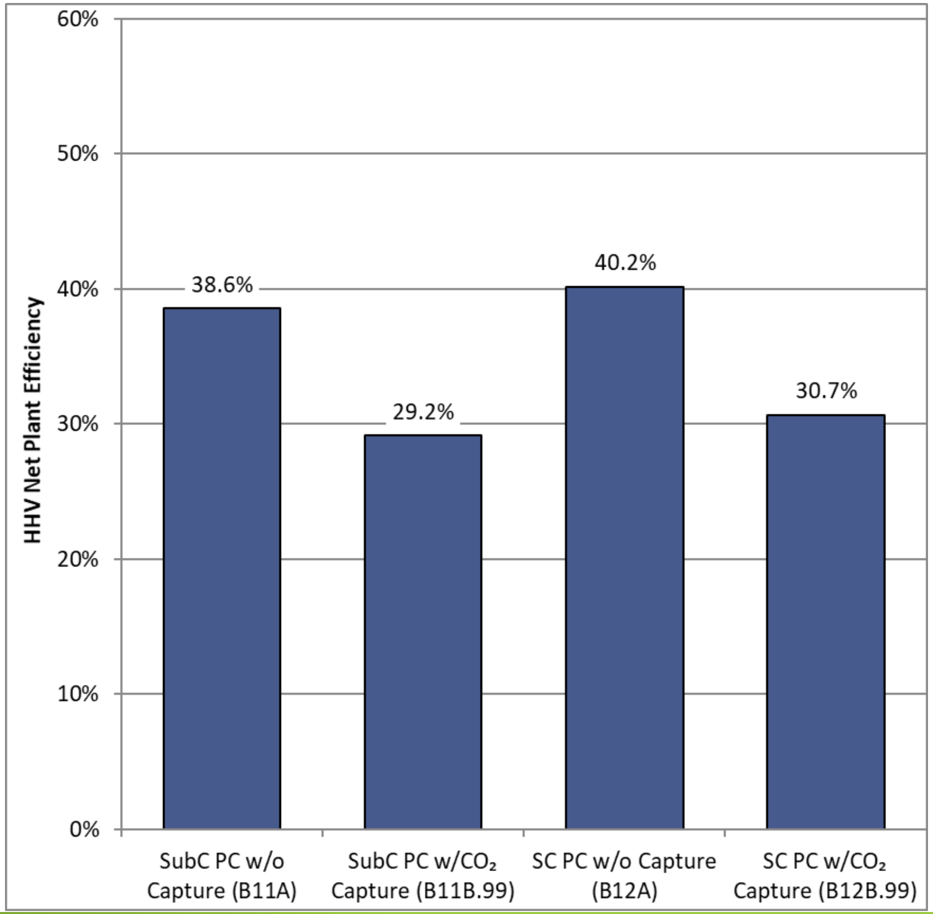

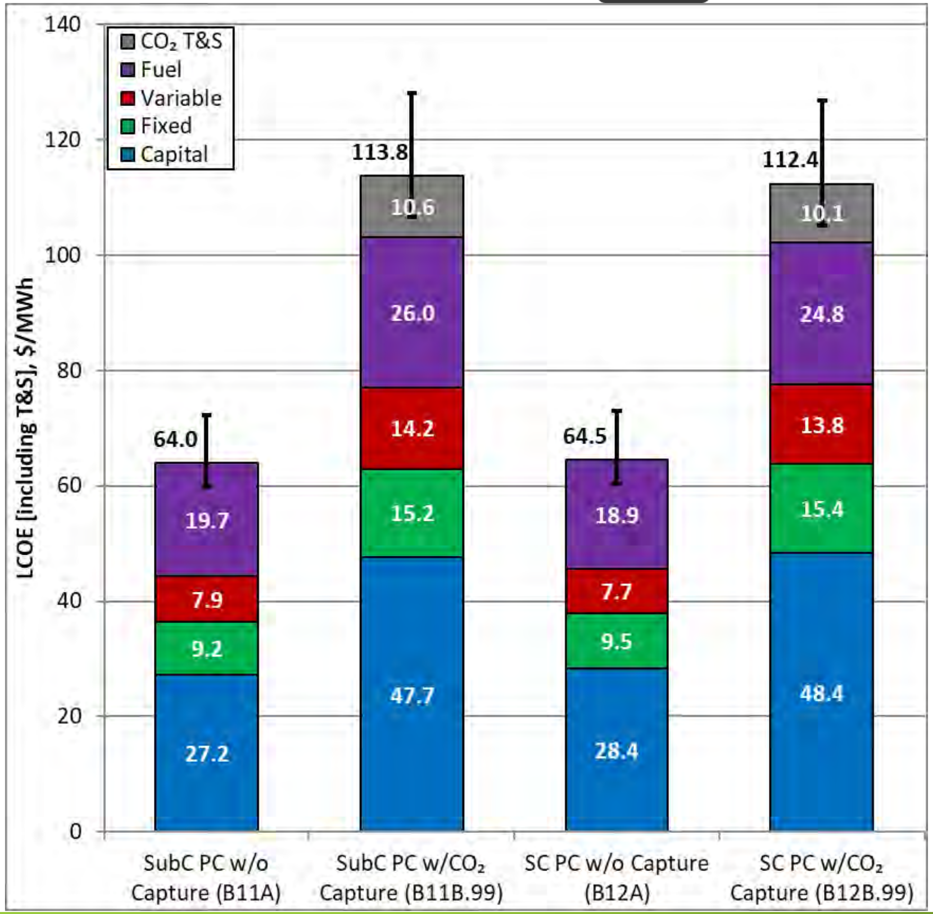

NGCC with 97% CO_2 Capture vs. No Capture

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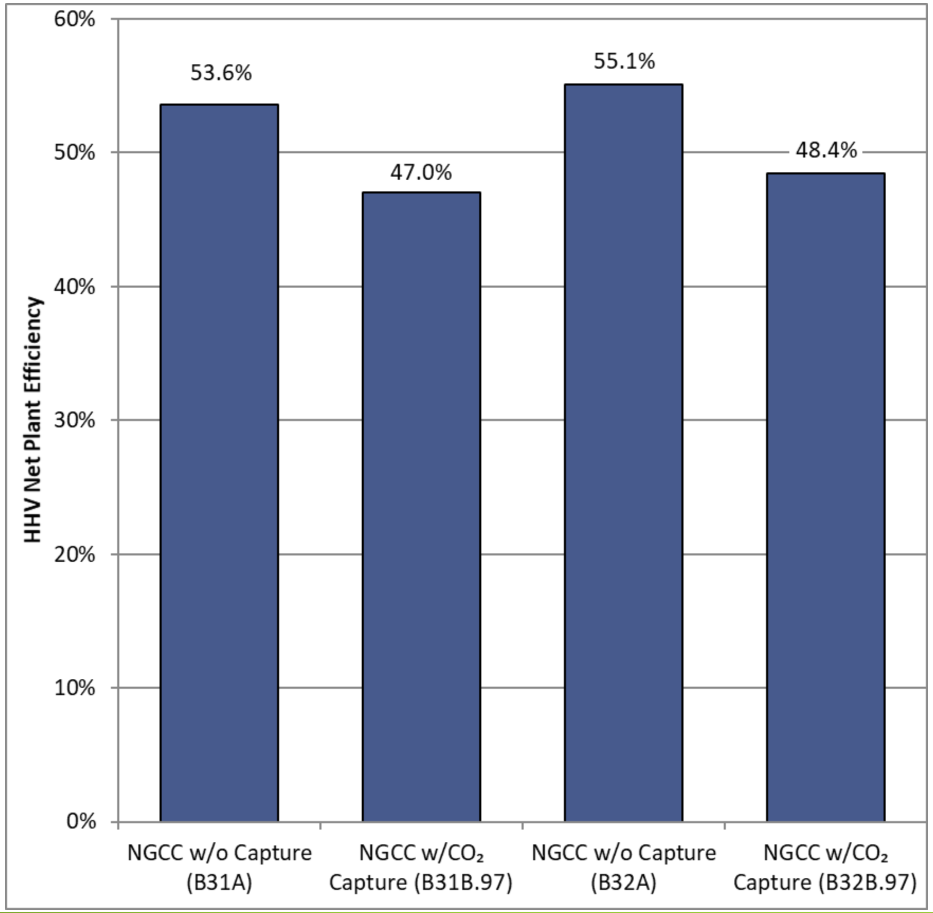

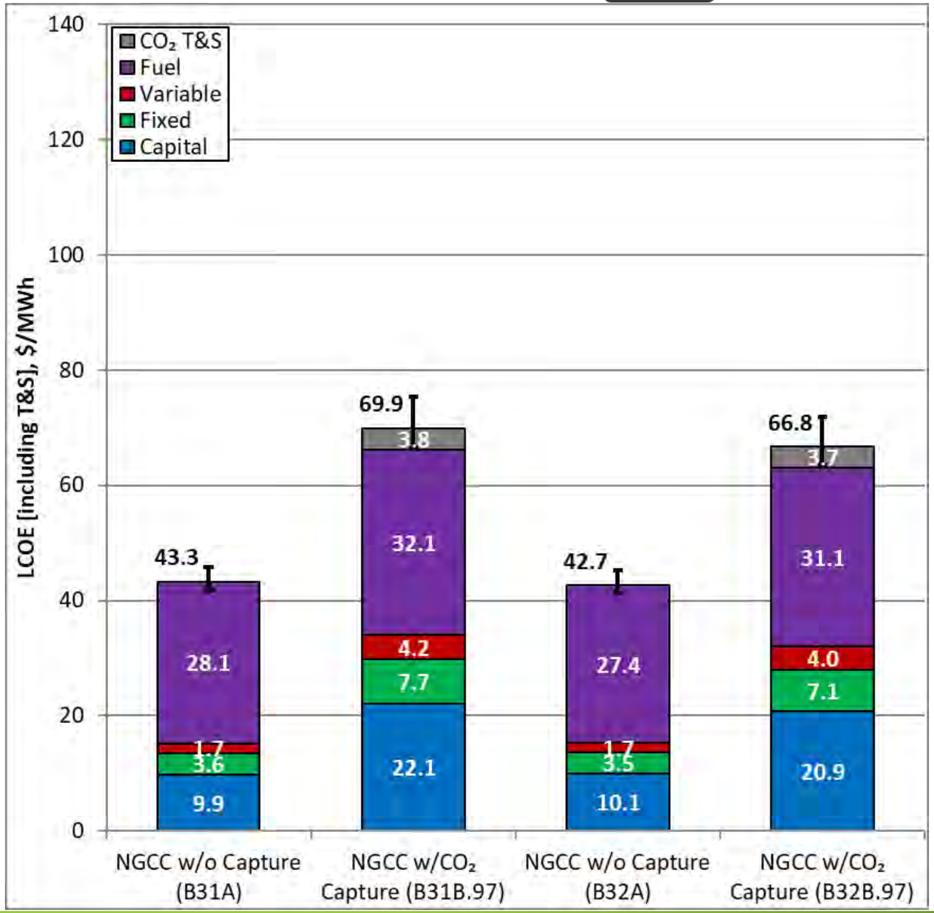

Completed and Future Work

- Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity – Revision 4A
  - Published October 2022: https://www.osti.gov/biblio/1893822
- Related/derivative studies:
  - Cost of Capturing CO_2 from Industrial Sources - Revision 1 and associated carbon capture retrofit database (CCRD) – September 2022
    - Report available at https://www.osti.gov/biblio/1887586
    - CCRD Model available at https://www.osti.gov/biblio/1887588
    - User Guide available at https://www.osti.gov/biblio/1887587
  - Cost and Performance of Retrofitting NGCC Units for Carbon Capture and associated Carbon Capture Retrofit Database (CCRD) – February 2023
  - Eliminating the Derate of Carbon Capture Retrofits and associated CCRD – 2023
  - Detailed cost sensitivity for NGCC with carbon capture and storage – 2023
  - Technoeconomic and Life Cycle Analysis of Bio-Energy with Carbon Capture and Storage (BECCS) Baseline – 2023

Disclaimer

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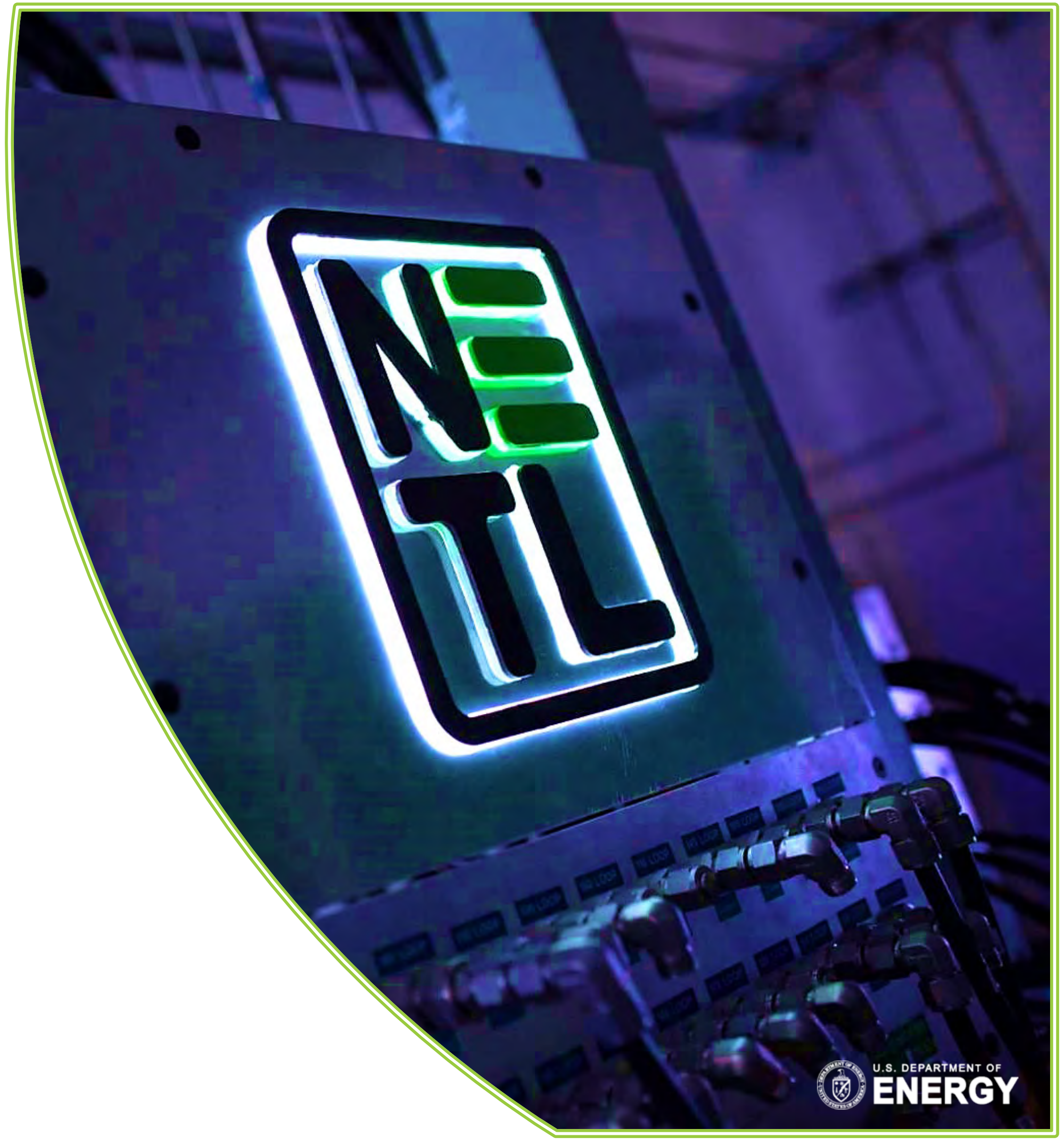
Questions?



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Supplemental Slides

Subcritical PC Plants

Performance Summary	B11A	B11B.90	B11B.95
Total Gross Power, MWe	**688**	**769**	**774**
CO_2 Capture/Removal Auxiliaries, kWe	–	18,800	20,200
CO_2 Compression, kWe	–	48,660	52,170
Balance of Plant, kWe	37,520	50,620	51,470
Total Auxiliaries, MWe	**38**	**118**	**124**
Net Power, MWe	**650**	**650**	**650**
Higher Heating Value (HHV) Net Plant Efficiency, %	38.6	30.2	29.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,336 (8,849)	11,940 (11,317)	12,128 (11,495)
Lower Heating Value (LHV) Net Plant Efficiency, %	40.0	31.3	30.8
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,005 (8,535)	11,516 (10,915)	11,697 (11,087)
HHV Boiler Efficiency, %	88.0	88.0	88.0
LHV Boiler Efficiency, %	91.3	91.3	91.3
Steam Turbine Cycle Efficiency, %	46.3	55.1	55.8
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,770 (7,365)	6,532 (6,191)	6,453 (6,116)
Condenser Duty, GJ/hr (MMBtu/hr)	2,793 (2,648)	2,312 (2,191)	2,277 (2,158)
Capture Rate (%)	–	90	95
Acid Gas Removal (AGR) Duty, GJ/hr (MMBtu/hr)	–	2,162 (2,050)	2,288 (2,169)
As-Received Coal Feed, kg/hr (lb/hr)	223,673 (493,115)	286,189 (630,940)	290,670 (640,819)
Limestone Sorbent Feed, kg/hr (lb/hr)	21,637 (47,701)	27,684 (61,033)	28,118 (61,989)
HHV Thermal Input, kWt	1,685,945	2,157,162	2,190,938
LHV Thermal Input, kWt	1,626,114	2,080,609	2,113,187
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.038 (10.0)	0.058 (15.3)	0.059 (15.7)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.030 (8.0)	0.043 (11.4)	0.044 (11.7)
Excess Air, %	20.3	20.3	20.3

Power Summary	B11A	B11B.90	B11B.95
Steam Turbine Power, MWe	688	769	774
Total Gross Power, MWe	**688**	**769**	**774**
Auxiliary Load Summary			
Activated Carbon Injection, kWe	30	40	40
Ash Handling, kWe	730	940	950
Baghouse, kWe	100	120	120
Circulating Water Pumps, kWe	5,700	9,670	9,900
CO_2 Capture/Removal Auxiliaries, kWe	–	18,800	20,200
CO_2 Compression, kWe	–	48,660	52,170
Coal Handling and Conveying, kWe	480	540	550
Condensate Pumps, kWe	720	720	720
Cooling Tower Fans, kWe	2,950	5,000	5,120
Dry Sorbent Injection, kWe	60	80	80
Flue Gas Desulfurizer, kWe	3,460	4,420	4,490
Forced Draft Fans, kWe	1,150	1,470	1,490
Ground Water Pumps, kWe	590	900	920
Induced Draft Fans, kWe	10,600	13,570	13,780
Miscellaneous Balance of Plant[A,B], kWe	2,250	2,250	2,250
Primary Air Fans, kWe	1,360	1,740	1,770
Pulverizers, kWe	3,350	4,290	4,360
Selective Catalytic Reduction, kWe	40	50	50
Sorbent Handling & Reagent Preparation, kWe	1,040	1,330	1,350
Spray Dryer Evaporator, kWe	250	320	320
Steam Turbine Auxiliaries, kWe	500	500	500
Transformer Losses, kWe	2,160	2,670	2,710
Total Auxiliaries, MWe	**38**	**118**	**124**
Net Power, MWe	**650**	**650**	**650**

[A] Boiler feed pumps are turbine driven
[B] Includes plant control systems; lighting; heating, ventilation, and combined cycle (HVAC); and miscellaneous low voltage loads

Supercritical PC Plants

Performance Summary	B12A	B12B.90	B12B.95
Total Gross Power, MWe	686	763	768
CO_2 Capture/Removal Auxiliaries, kWe	–	17,900	19,200
CO_2 Compression, kWe	–	46,330	49,640
Balance of Plant, kWe	35,950	48,270	49,030
Total Auxiliaries, MWe	**36**	**113**	**118**
Net Power, MWe	**650**	**650**	**650**
Higher Heating Value (HHV) Net Plant Efficiency, %	40.2	31.7	31.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,957 (8,490)	11,371 (10,778)	11,540 (10,938)
Lower Heating Value (LHV) Net Plant Efficiency, %	41.7	32.8	32.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,639 (8,188)	10,968 (10,396)	11,131 (10,550)
HHV Boiler Efficiency, %	88.0	88.0	88.0
LHV Boiler Efficiency, %	91.3	91.3	91.3
Steam Turbine Cycle Efficiency, %	48.2	57.4	58.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,471 (7,081)	6,267 (5,940)	6,189 (5,866)
Condenser Duty, GJ/hr (MMBtu/hr)	2,592 (2,457)	2,100 (1,990)	2,064 (1,956)
Capture Rate (%)	–	90	95
AGR Duty, GJ/hr (MMBtu/hr)	–	2,059 (1,952)	2,177 (2,064)
As-Received Coal Feed, kg/hr (lb/hr)	214,574 (473,055)	272,519 (600,801)	276,574 (609,741)
Limestone Sorbent Feed, kg/hr (lb/hr)	20,757 (45,761)	26,362 (58,118)	26,754 (58,983)
HHV Thermal Input, kWt	1,617,359	2,054,118	2,084,684
LHV Thermal Input, kWt	1,559,963	1,981,222	2,010,703
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.035 (9.3)	0.054 (14.3)	0.055 (14.6)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.028 (7.4)	0.040 (10.6)	0.041 (10.9)
Excess Air, %	20.3	20.3	20.3

Power Summary	B12A	B12B.90	B12B.95
Steam Turbine Power, Mwe	686	763	768
Total Gross Power, Mwe	**686**	**763**	**768**
Auxiliary Load Summary			
Activated Carbon Injection, kWe	30	40	40
Ash Handling, kWe	700	890	910
Baghouse, kWe	90	120	120
Circulating Water Pumps, kWe	5,300	9,020	9,230
CO_2 Capture/Removal Auxiliaries, kWe	–	17,900	19,200
CO_2 Compression, kWe	–	46,330	49,640
Coal Handling and Conveying, kWe	470	530	530
Condensate Pumps, kWe	660	790	800
Cooling Tower Fans, kWe	2,740	4,670	4,770
Dry Sorbent Injection, kWe	60	80	80
Flue Gas Desulfurizer, kWe	3,320	4,210	4,270
Forced Draft Fans, kWe	1,100	1,400	1,420
Ground Water Pumps, kWe	500	840	860
Induced Draft Fans, kWe	10,230	12,920	13,110
Miscellaneous Balance of Plant[A,B], kWe	2,250	2,250	2,250
Primary Air Fans, kWe	1,310	1,660	1,680
Pulverizers, kWe	3,220	4,090	4,150
Selective Catalytic Reduction, kWe	30	50	50
Sorbent Handling & Reagent Preparation, kWe	1,000	1,270	1,290
Spray Dryer Evaporator, kWe	240	300	300
Steam Turbine Auxiliaries, kWe	500	500	500
Transformer Losses, kWe	2,150	2,640	2,670
Total Auxiliaries, MWe	**36**	**113**	**118**
Net Power, MWe	**650**	**650**	**650**

[A] Boiler feed pumps are turbine driven
[B] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

F-Class NGCC Plants

Performance Summary	B31A	B31B.90	B31B.95
Combustion Turbine Power, MWe	477	477	477
Steam Turbine Power, MWe	263	215	212
Total Gross Power, MWe	**740**	**692**	**690**
CO_2 Capture/Removal Auxiliaries, kWe	–	13,600	14,400
CO_2 Compression, kWe	–	17,900	18,900
Balance of Plant, kWe	13,562	15,992	16,042
Total Auxiliaries, MWe	**14**	**47**	**49**
Net Power, MWe	**727**	**645**	**640**
HHV Net Plant Efficiency, %	53.6	47.6	47.3
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,714 (6,363)	7,563 (7,169)	7,617 (7,220)
HHV Combustion Turbine Efficiency, %	35.2	35.2	35.2
LHV Net Plant Efficiency, %	59.4	52.7	52.4
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,060 (5,743)	6,827 (6,470)	6,875 (6,516)
LHV Combustion Turbine Efficiency, %	39.0	39.0	39.0
Steam Turbine Cycle Efficiency, %	39.7	46.9	47.5
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,074 (8,601)	7,678 (7,277)	7,586 (7,190)
CO_2 Capture Rate, %	0	90	95
Condenser Duty, GJ/hr (MMBtu/hr)	1,406 (1,332)	860 (815)	830 (787)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–	1,194 (1,132)	1,232 (1,167)
Natural Gas Feed Flow, kg/hr (lb/hr)	93,272 (205,630)	93,272 (205,630)	93,272 (205,630)
HHV Thermal Input, kWt	1,354,905	1,354,905	1,354,905
LHV Thermal Input, kWt	1,222,936	1,222,936	1,222,936
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.015 (4.0)	0.026 (6.9)	0.027 (7.0)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.012 (3.1)	0.017 (4.6)	0.018 (4.7)

Power Summary	B31A	B31B.90	B31B.95
Combustion Turbine Power, MWe	477	477	477
Steam Turbine Power, MWe	263	215	212
Total Gross Power, MWe	**740**	**692**	**690**
Auxiliary Load Summary			
Circulating Water Pumps, kWe	2,820	4,340	4,360
Combustion Turbine Auxiliaries, kWe	1,020	1,020	1,020
Condensate Pumps, kWe	150	170	170
Cooling Tower Fans, kWe	1,460	2,240	2,260
CO_2 Capture/Removal Auxiliaries, kWe	–	13,600	14,400
CO_2 Compression, kWe	–	17,900	18,900
Feedwater Pumps, kWe	4,830	4,830	4,830
Ground Water Pumps, kWe	260	400	410
Miscellaneous Balance of Plant[A], kWe	570	570	570
SCR, kWe	2	2	2
Steam Turbine Auxiliaries, kWe	200	200	200
Transformer Losses, kWe	2,250	2,220	2,220
Total Auxiliaries, MWe	**14**	**47**	**49**
Net Power, MWe	**727**	**645**	**640**

[A] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

H-Class NGCC Plants

Performance Summary	B32A	B32B.90	B32B.95
Combustion Turbine Power, MWe	686	686	686
Steam Turbine Power, MWe	324	260	256
Total Gross Power, MWe	**1,009**	**945**	**942**
CO_2 Capture/Removal Auxiliaries, kWe	–	18,000	19,200
CO_2 Compression, kWe	–	23,810	25,130
Balance of Plant, kWe	16,923	20,153	20,213
Total Auxiliaries, MWe	**17**	**62**	**65**
Net Power, MWe	**992**	**883**	**877**
HHV Net Plant Efficiency, %	55.1	49.0	48.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,537 (6,196)	7,342 (6,959)	7,393 (7,007)
HHV Combustion Turbine Efficiency, %	38.0	38.0	38.0
LHV Net Plant Efficiency, %	61.0	54.3	54.0
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	5,900 (5,592)	6,627 (6,281)	6,672 (6,324)
LHV Combustion Turbine Efficiency, %	42.2	42.2	42.2
Steam Turbine Cycle Efficiency, %	39.1	46.7	47.3
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,213 (8,732)	7,713 (7,311)	7,609 (7,212)
CO_2 Capture Rate, %	0	90	95
Condenser Duty, GJ/hr (MMBtu/hr)	1,757 (1,666)	1,031 (978)	992 (940)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–	1,587 (1,505)	1,638 (1,552)
Natural Gas Feed Flow, kg/hr (lb/hr)	124,025 (273,429)	124,025 (273,429)	124,025 (273,429)
HHV Thermal Input, kWt	1,801,631	1,801,631	1,801,631
LHV Thermal Input, kWt	1,626,150	1,626,150	1,626,150
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.014 (3.6)	0.024 (6.4)	0.025 (6.5)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.011 (2.8)	0.016 (4.2)	0.016 (4.3)

Power Summary	B32A	B32B.90	B32B.95
Combustion Turbine Power, MWe	686	686	686
Steam Turbine Power, MWe	324	260	256
Total Gross Power, MWe	**1,009**	**945**	**942**
Auxiliary Load Summary			
Circulating Water Pumps, kWe	3,510	5,530	5,570
Combustion Turbine Auxiliaries, kWe	1,320	1,320	1,320
Condensate Pumps, kWe	180	200	200
Cooling Tower Fans, kWe	1,810	2,860	2,880
CO_2 Capture/Removal Auxiliaries, kWe	–	18,000	19,200
CO_2 Compression, kWe	–	23,810	25,130
Feedwater Pumps, kWe	5,760	5,760	5,760
Ground Water Pumps, kWe	330	520	520
Miscellaneous Balance of Plant[A], kWe	710	710	710
SCR, kWe	3	3	3
Steam Turbine Auxiliaries, kWe	230	230	230
Transformer Losses, kWe	3,070	3,020	3,020
Total Auxiliaries, MWe	**17**	**62**	**65**
Net Power, MWe	**992**	**883**	**877**

[A] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Winter Storm Elliott

Mike Bryson, Sr. Vice President – System Operations

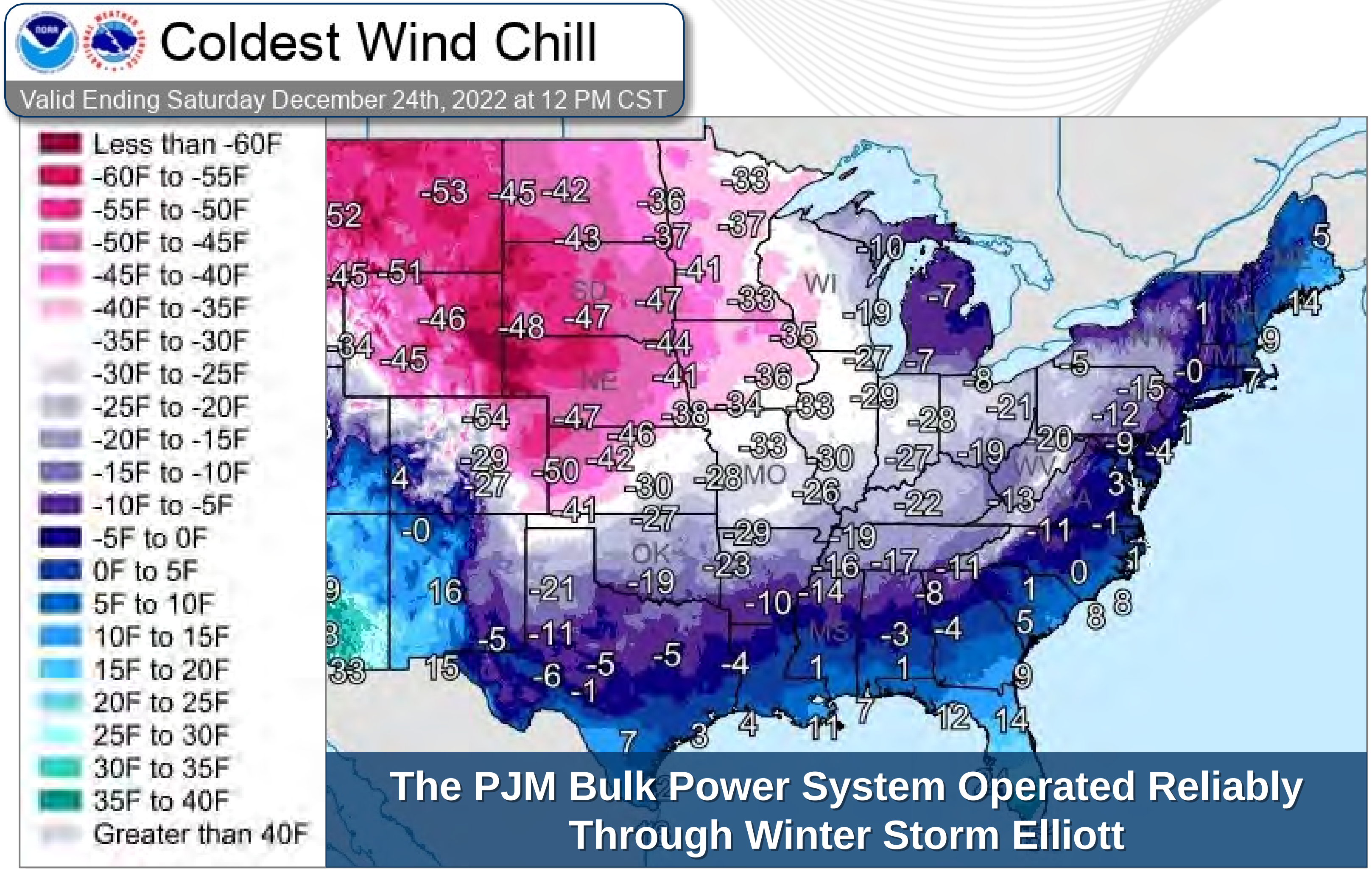
Donnie Bielak, Sr. Manager – Dispatch

Stu Bresler, Sr. Vice President – Market Services

Brian Chmielewski, Manager – Real-Time Market Operations

Susan Kenney, Manager – Market Settlements Development

Winter Storm Elliott



Source: NOAA and the National Weather Service; Graphic created on Dec. 21, 2022.

Source: NOAA

Temperatures across the RTO plummeted beginning on Dec. 23 and lasted into the morning of Dec. 25 with record lows in some areas as well as record drops in some regions.

PJM Prepares Extensively for the Winter

Winter readiness assessments: data collection on fuel inventory, supply and delivery characteristics, emissions limitations, and minimum operating temperatures

Meetings with federal and state regulators and neighboring systems to review winter preparations; weekly operational review meetings with major natural gas pipeline operators

PJM's Cold Weather Preparation Guideline and Checklist for generation owners includes everything from increasing staffing for weather emergencies to performing required maintenance activities.

April 2023 NERC winterization standard implementation is important. PJM feedback to NERC and FERC: New reliability standards need to be stronger and implemented sooner.

Prior to Storm, PJM Issued Winter Advisory and Alerts

Dec. 20, 2022

Cold Weather Advisory for Western Region From Dec. 23–26 (Later Expanded to Entire RTO)

- Prepare to take freeze-protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts, determine any forecasted operational changes, and notify PJM of any changes.
- Members are to update PJM with operation limitations associated with cold weather preparedness. Operating limitations include: generator capability and availability, fuel supply and inventory concerns, fuel switching capabilities, environmental constraints, generating unit minimums.

Dec. 21, 2022

Cold Weather Alert Issued for the Western Region for Dec. 23

- Generation dispatchers review fuel supply/delivery schedules in anticipation of greater-than-normal operation of units.
- Generation dispatchers monitor and report projected fuel limitations to PJM dispatcher and update the unit Max Run field in Markets Gateway if less than 24 hours of run time remaining.
- Generation dispatchers contact PJM Dispatch if it is anticipated that spot market gas is unavailable, resulting in unavailability of bid-in generation.

Dec. 23, 2022

Second Cold Weather Alert Issued for the Entire RTO for Christmas Eve, Dec. 24

PJM's Dec. 23 Operating Plan Was Conservative

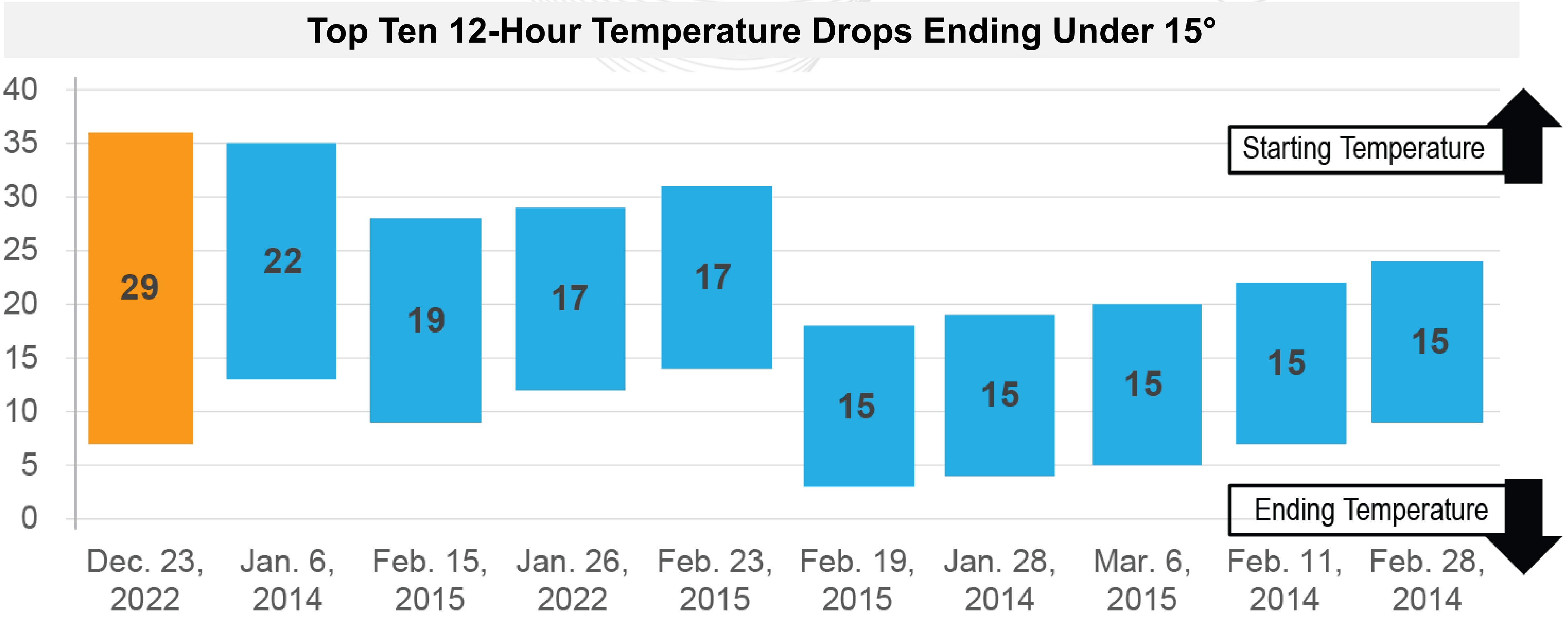
PJM accounts for uncertainty and unplanned events as it develops the operating plan for every day.

- Given the expected weather, PJM was conservative in developing the operating plans for Dec. 23.
- Forecast load was 126,968 MW.
- PJM called over 155,750 MW into the operating capacity for the day.

Based on generator availability data submitted to PJM, we believed we had almost 29 GW of reserve capacity available to absorb load and generation contingencies and to support our neighboring systems.

Preliminary Data

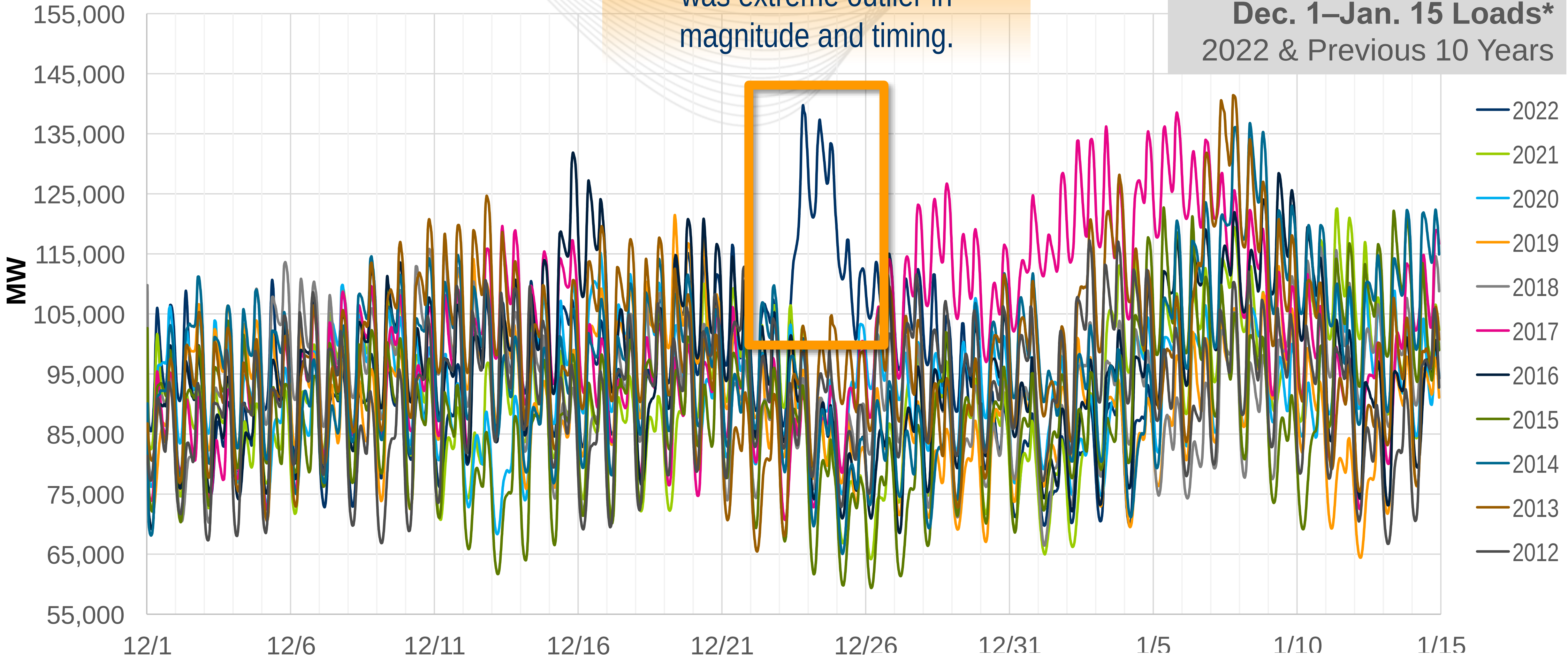
Most Drastic Temperature Drop in a Decade



2022 Holiday Load
(Preliminary Data)

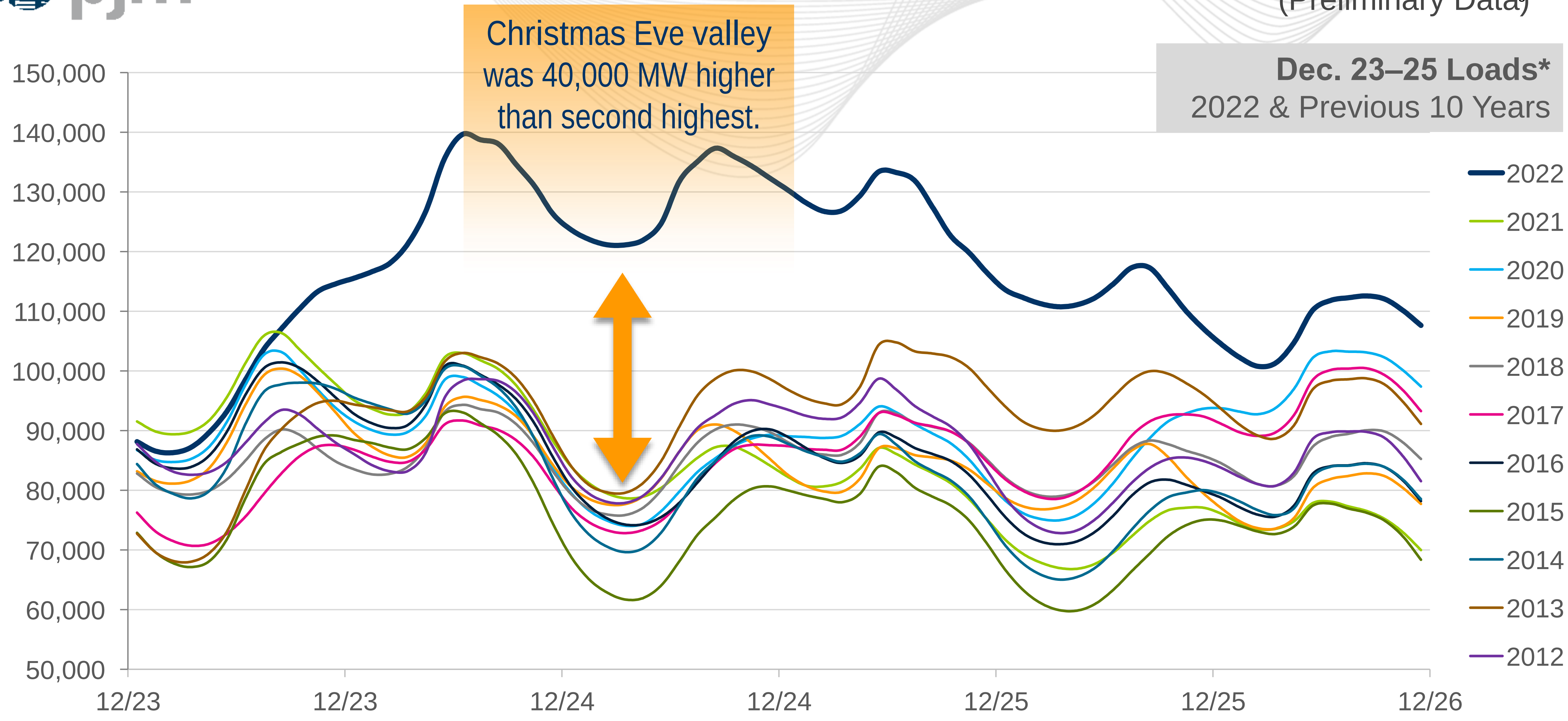
2022 holiday weekend load was extreme outlier in magnitude and timing.

Dec. 1–Jan. 15 Loads*
2022 & Previous 10 Years



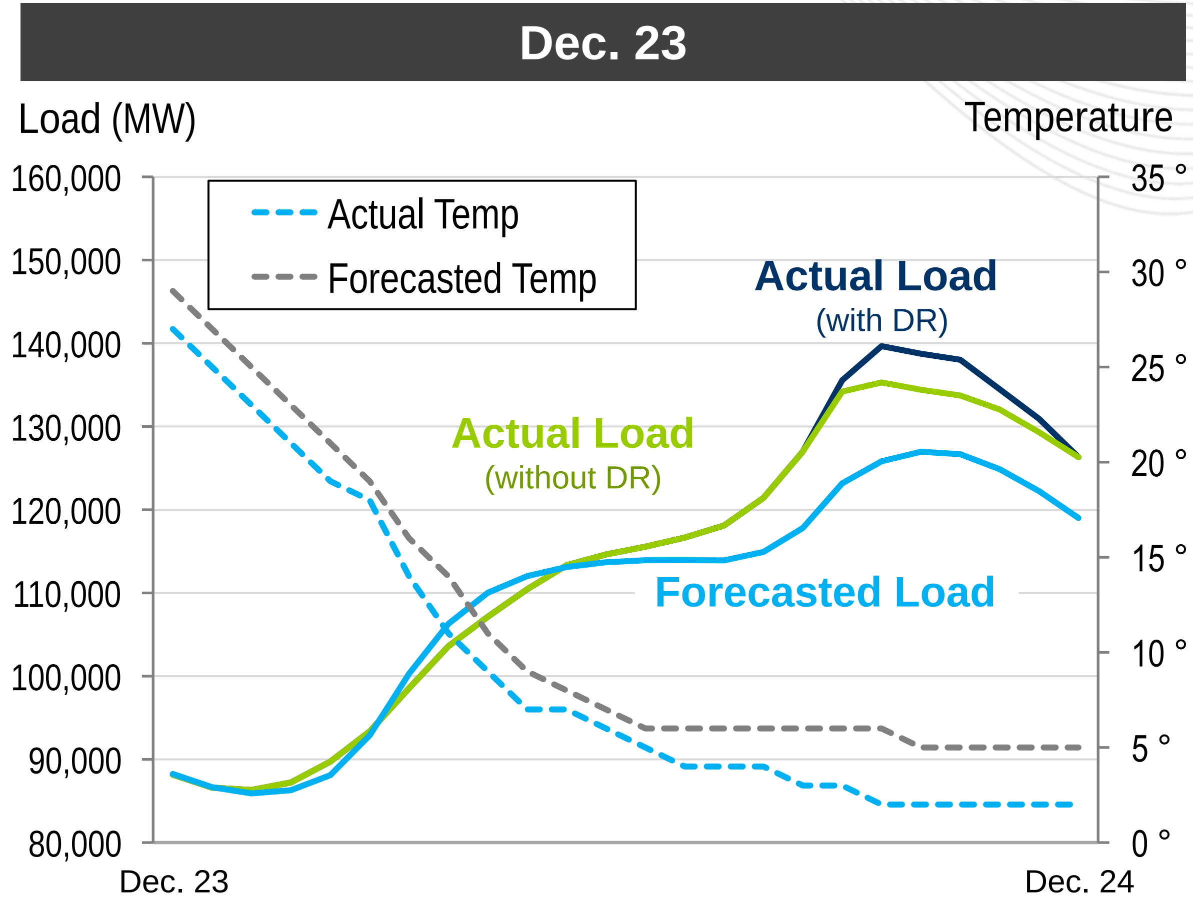
Note: Load values include the estimated demand response (DR) added back.

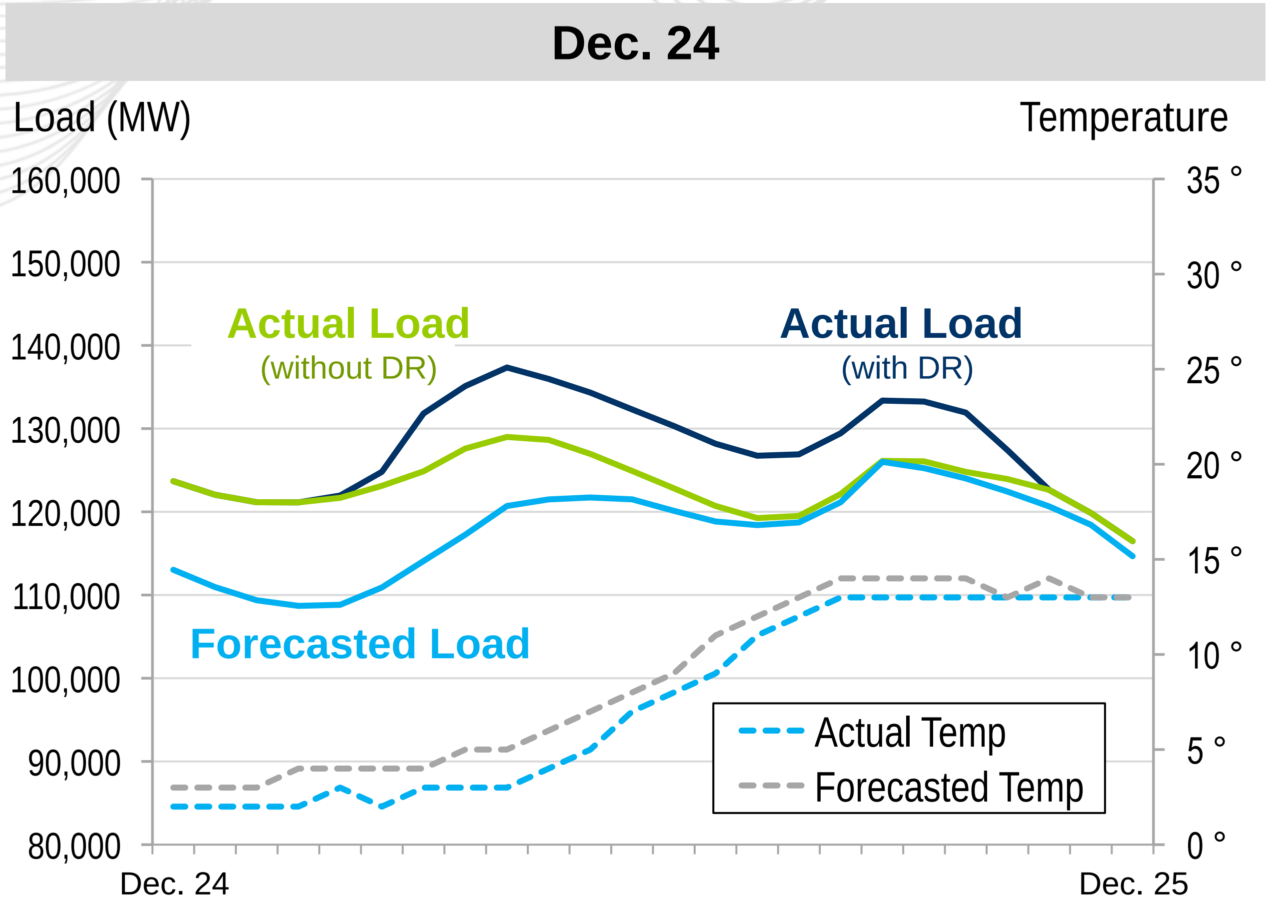
Load Stayed Unusually High Overnight
(Preliminary Data)



Note: Load values include the estimated demand response (DR) added back.

Actual Load Came in Higher Than Forecast (Preliminary Data)



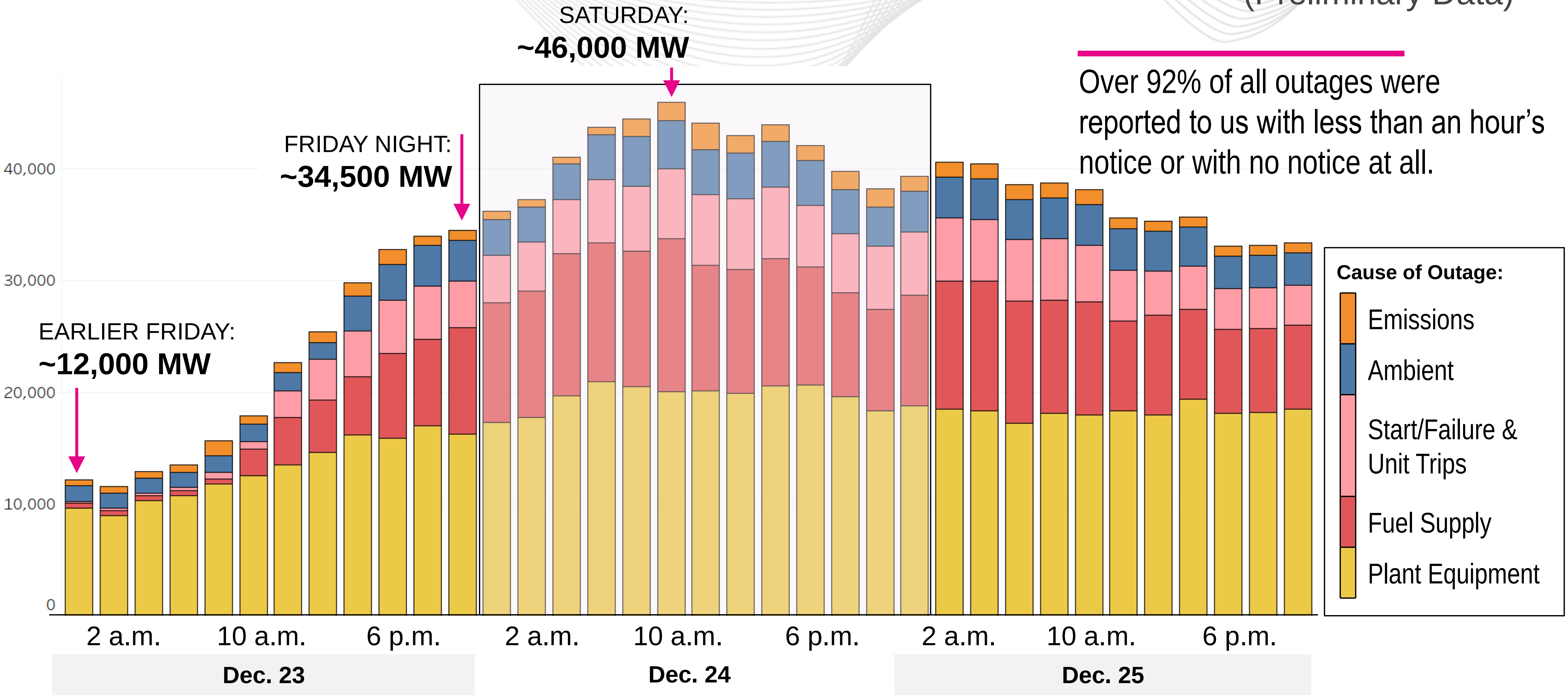


Actual load came in over 10% over forecast.

- Severe cold and blizzard conditions
- Most drastic temperature drop in a decade
- Early occurrence of cold weather
- Holiday impacts: rare instance of under-forecasting

As We Called Reserves, a Significant Portion of Fleet Failed To Perform (Preliminary Data)

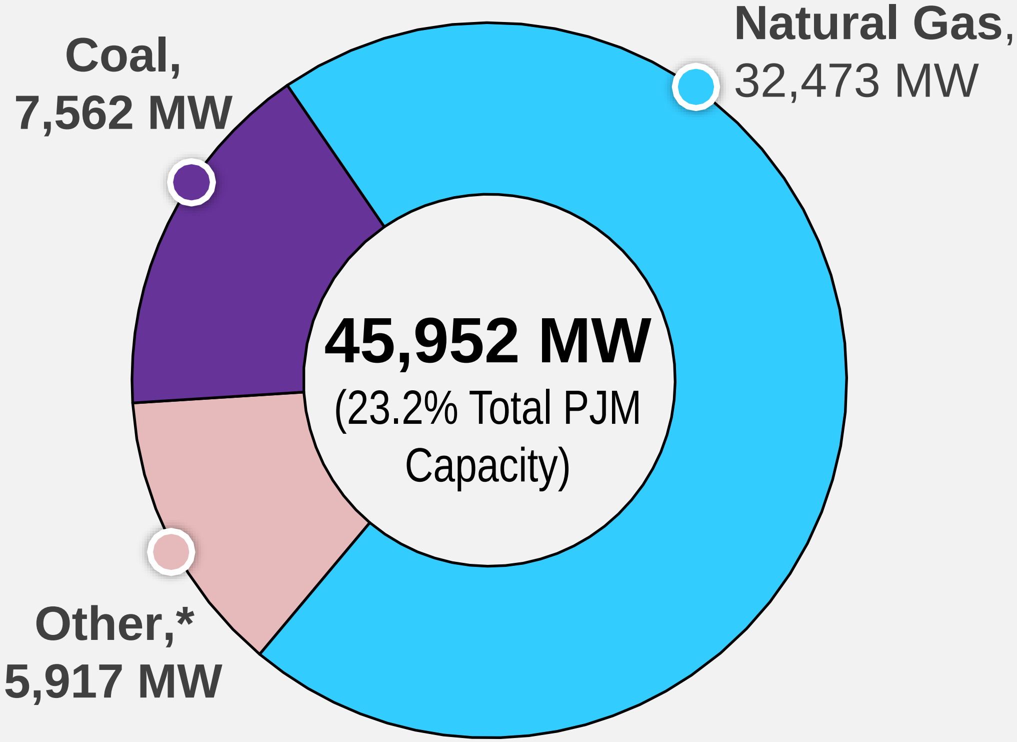
Over 92% of all outages were reported to us with less than an hour's notice or with no notice at all.



Case No. U-21193
Exhibit CEO-26
Witness: Lucas
Date: March 9, 2023
Page 11 of 32

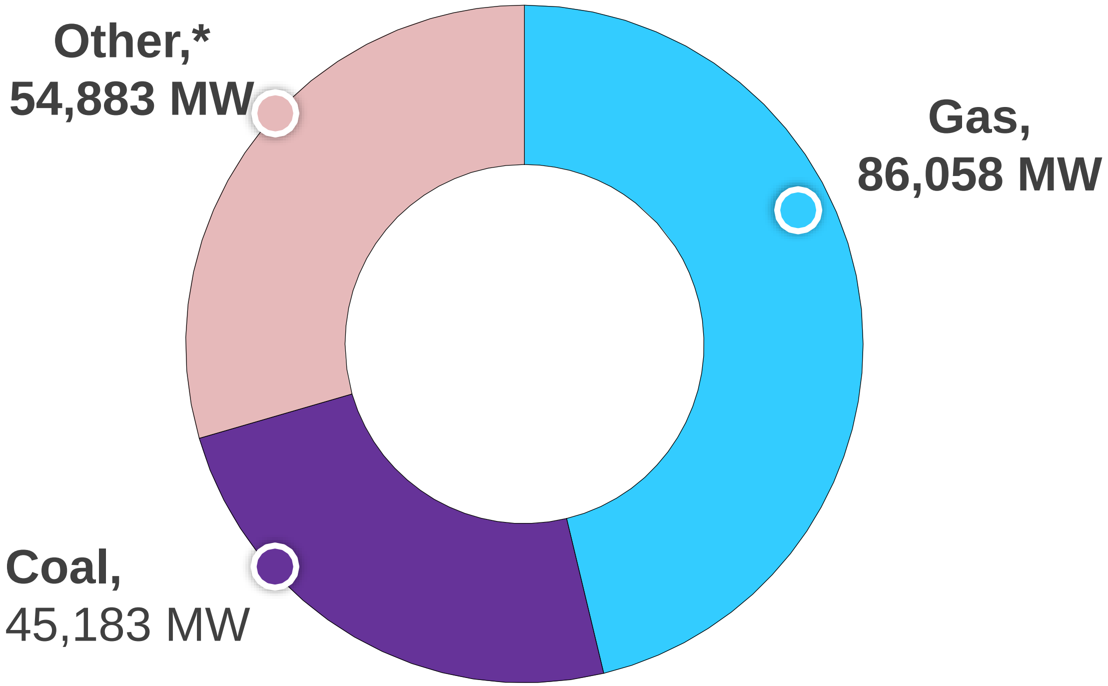
Generator Performance
(Preliminary Data)

TOTAL FORCED OUTAGES – DEC. 24, 2022



*Other = nuclear, oil, wind, solar, etc.

GENERATOR UCAP 2022/2023 DELIVERY YEAR



PJM's Total Fleet Capacity – **186 GW**

Certain Generation Was Unable To Start at Stated Start Times (Preliminary Data)

- In addition to forced outages, ~6,000 MW of steam generation was called but was not on-line as expected per their time to start for the morning peak on Dec. 24.

  The vast majority of these resources were gas-fired resources.

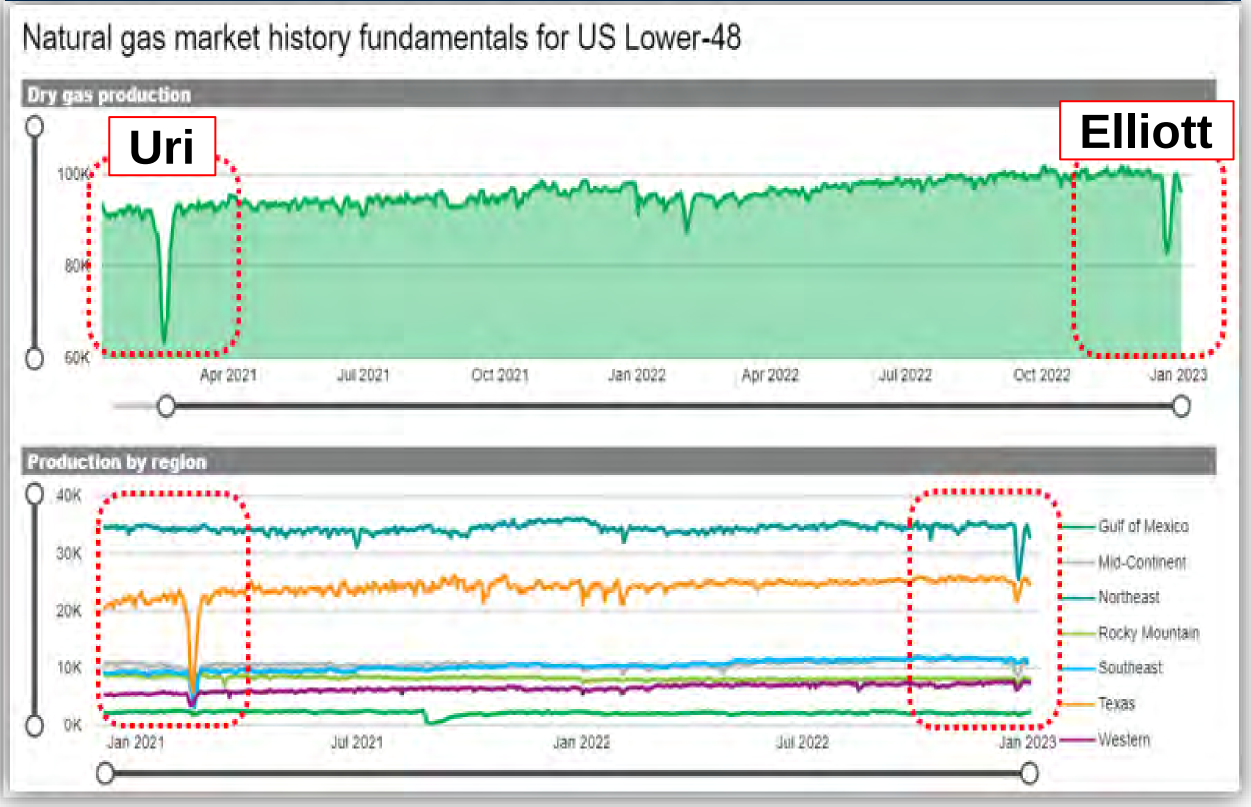
- The high rates of generator outages also limited our ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24.

  That left PJM with extremely limited run hours for pumped storage generation.

- Between forced outages, derates, generators that did not start on time, and the inability to fill pumped storage hydro ponds, PJM was dealing with ~57 GW of generator unavailability for the Dec. 24 morning peak.

Natural Gas Production Declines Uri (February 2021) vs. Elliott (December 2022)

Jan. 1, 2021, through Jan. 2, 2023



Northeast: Marcellus and Utica Shale; Data Source: S&P Global

Uri (February 2021)

- 30% nationwide production decline
- All production loss in Texas and Southwest
- No production loss in Appalachia

Elliott (December 2022)

- 20% nationwide production decline
- Largest percentage of total decline in Appalachia (Marcellus and Utica), which saw a nearly 30% drop in daily production
- Production has returned to near pre-event levels.

Emergency Procedures
(Preliminary Data)

- Cold Weather Alert issued from 07:00 on 12/23 through 23:00 on 12/25 for Western Region.
- Cold Weather Advisory extended to 07:00 on 12/23 through 23:00 on 12/26 for Western Region.

- **12/23 17:30–22:15** – Pre-Emergency Load Mgmt. Reduction Action – RTO 30-minute response product
- **12/23 17:30–23:00** – Maximum Generation Emergency Action, Issues EEA2

PAI Trigger

- **12/23 17:45–21:30** – Emergency Load Mgmt. Reduction Action and a NERC level EEA2
- **12/23 18:00–22:15** – Pre-Emergency Load Mgmt. Reduction Action, 60-minute response product
- 12/23 23:00 – Max. Generation Emergency Alert/Load Mgmt. Alert for 12/24

- **12/24 04:25–22:00** – Max. Generation Emergency Action

PAI Trigger

- **12/24 04:52–18:34** – Voltage Reduction Alert issued for RTO
- **12/24 05:16–21:08** – Emergency Energy Request
- **12/24 07:15–18:15** – Voltage Reduction Warning and Reduction of NCPL
- ***17:45 – DOE issues Emergency Order under** Section 202 (c) of Federal Power Act*
- 12/24 22:30 – PJM downgrades EEA2 to EEA1.

Dec. 20 | **Dec. 21** | **Dec. 23** | **Dec. 24** | **Dec. 25**

Dec. 20

Cold Weather Advisory from 07:00 on 12/23 through 23:00 on 12/25 for Western Region.

PJM expands Cold Weather Advisory to the entire RTO on 12/22.

Dec. 23

- Cold Weather Alert issued from 00:00 on 12/24 through 23:59 on 12/25 for the RTO.
- **12/23 10:14–10:25** – Synch. Reserve Event
- **12/23 16:17–18:09** – Synch. Reserve Event

Dec. 24

- **12/24 00:04–00:30** – 100% Synchronized Reserve Event initiated for the PJM RTO region.
- **12/24 02:23–03:24** – 100% Synchronized Reserve Event initiated for the PJM RTO region.
- *PJM Issues Call for Conservation effective 04:00 on 12/24 through 10:00 on 12/25.*
- **12/24 04:20–20:30** – Emergency Load Mgmt. Reduction Action and a NERC level EEA2 issued – All load mgmt.

PAI Trigger

- **12/24 04:23–05:51** – 100% Synchronized Reserve Event initiated for the PJM RTO region.

Dec. 25

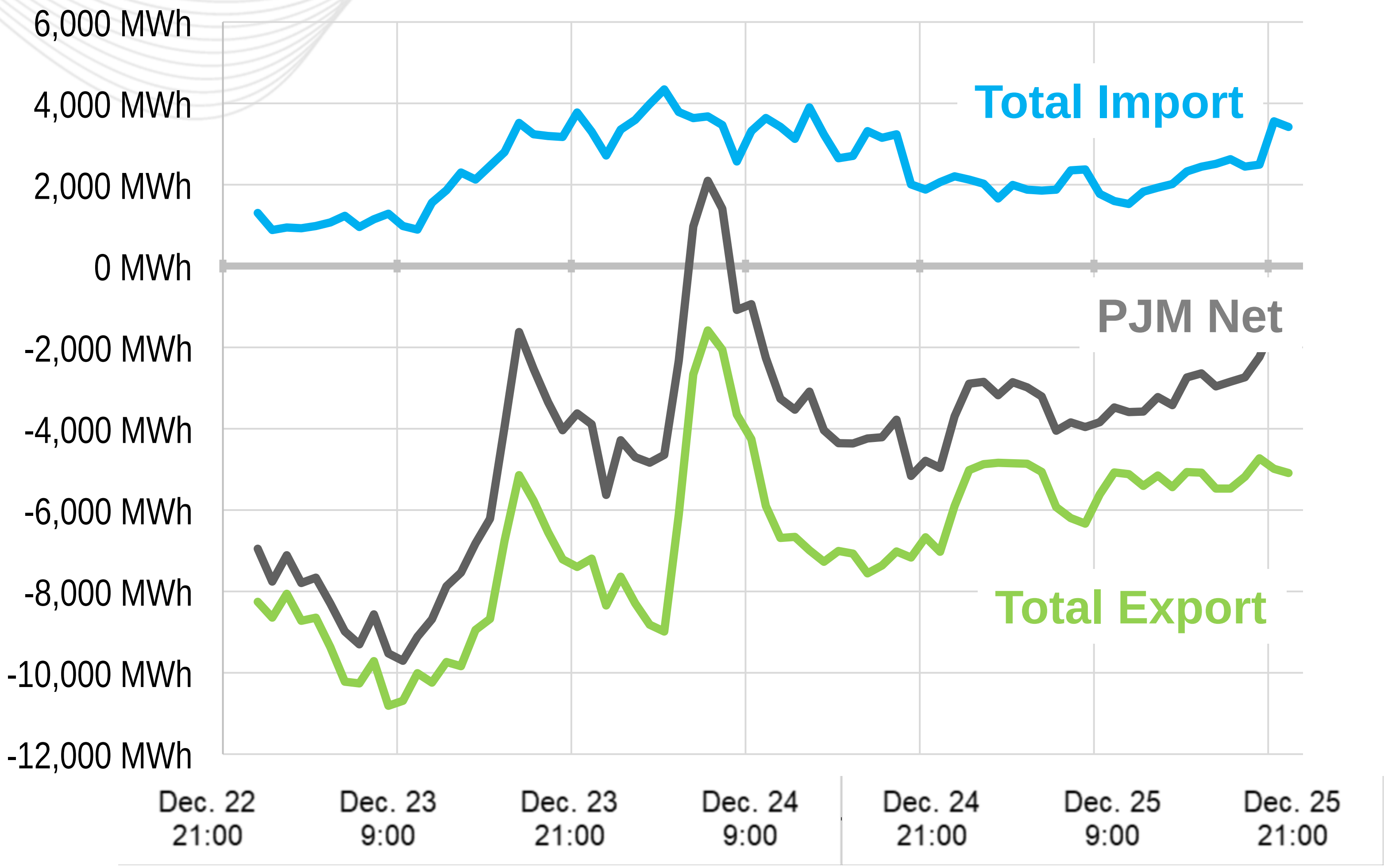
- 12/25 08:55 – Cold Weather Alert issued from 07:00 on 12/26 through 23:00 on 12/26 for Western Region
- 12/25 22:00 – EEA1 ends

Interchange: Dec. 23–25

Dec. 20 PJM total exports began increasing and peaked on Dec. 23 at 9 a.m. at 10,811 MWh.

Dec. 23 PJM began curtailing exports as our capacity position deteriorated due to the generation failures that we were having.

Net Scheduled Interchange – (not including dynamic transfers)



PJM Media Outreach

Used Media, Press Releases and Social Media Sites

PJM Interconnection Retweeted
NJ Board of Public Uti... @ · Dec 24, 2022
Our regional grid operator is asking the public to conserve electricity through 10:00AM on December 25, 2022 as frigid temps continue.
What you can do:
Set thermostats lower, if health permits
Postpone use of major appliances
Turn off non-essential lights & appliances

PJM Interco... @pjmint... · Dec 24, 2022
PJM asks consumers to... the face of continuing ... pjm.com/-/media/abou...
42

Worked With Utility Partners

pjm News

FOR IMMEDIATE RELEASE

Contact: PJM News, at PJMNews@pjm.com or toll free at 866-PJM-NEWS (866-756-6397)

PJM ASKS CONSUMERS TO CONSERVE ELECTRICITY

Cold Weather Continues to Push Electricity Use Higher

(Valley Forge, PA – Dec. 23, 2022) – PJM Interconnection, the electricity grid operator for 65 million people in 13 states and the District of Columbia, has requested the public in its region to conserve electricity. The call for conservation was prompted by continuing frigid weather.

The request is being made throughout PJM.

PJM Intercon... @pjmint... · Dec 24, 2022
Update from PJM Senior Vice President of Operations Mike Bryson.

27 84 69

PJM Interconnection Retweeted
Kentucky Po... @Kentucky... · Dec 24, 2022
PJM urging Kentucky Power customers to reduce use of electricity without sacrificing safety. Cold temps creating demands on power system. Minor adjustment to thermostats can make a difference. Info here: facebook.com/KentuckyPower - Thank you!

2 7 10

Analysis and Lessons Learned

What's next for PJM and members?

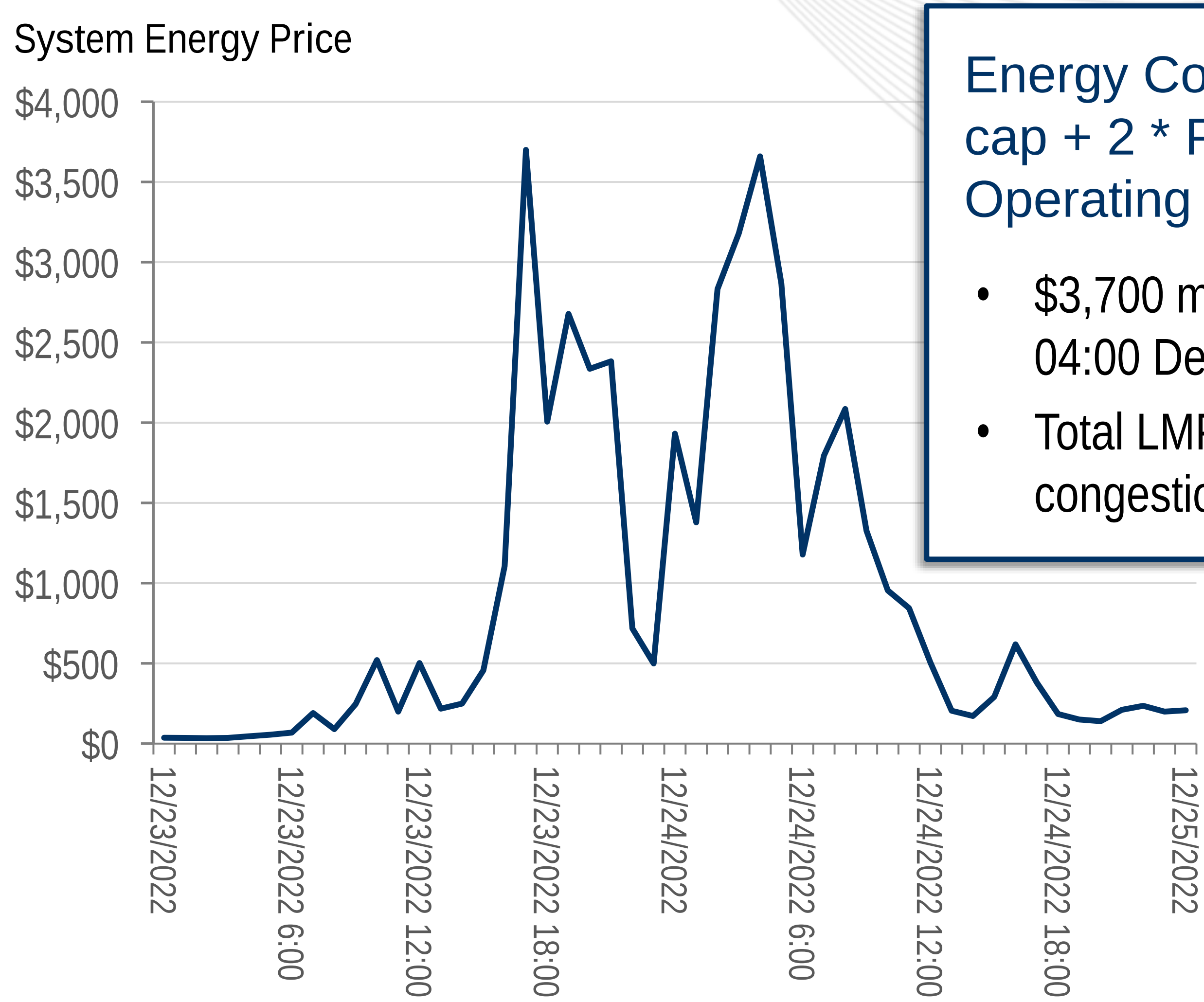
Look at some immediate actions to be prepared for the rest of this winter.

- Cold Weather Advisory steps
- Data request from affected resources
- Load forecast approach

PJM is doing a full analysis estimated mid-April.

NERC/FERC has announced a nationwide investigation. PJM has received requests for information from Reliability First and SERC.

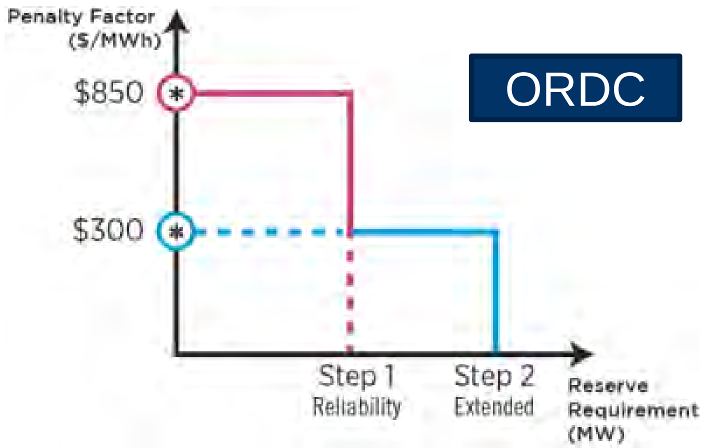
System Energy Price Overview



Energy Component of LMP is capped at the energy offer cap + 2 * Penalty Factor from first step of reserve Operating Reserve Demand Curve (ORDC).

- $3,700 multiple intervals, including all of 17:00 Dec. 23 and most of 04:00 Dec. 24
- Total LMPs were above this level when factoring in locational congestion and loss prices for multiple intervals.

Penalty Factor sets a price for being unable to meet the reserve requirement.



Impacts of Congestion

Dec. 23

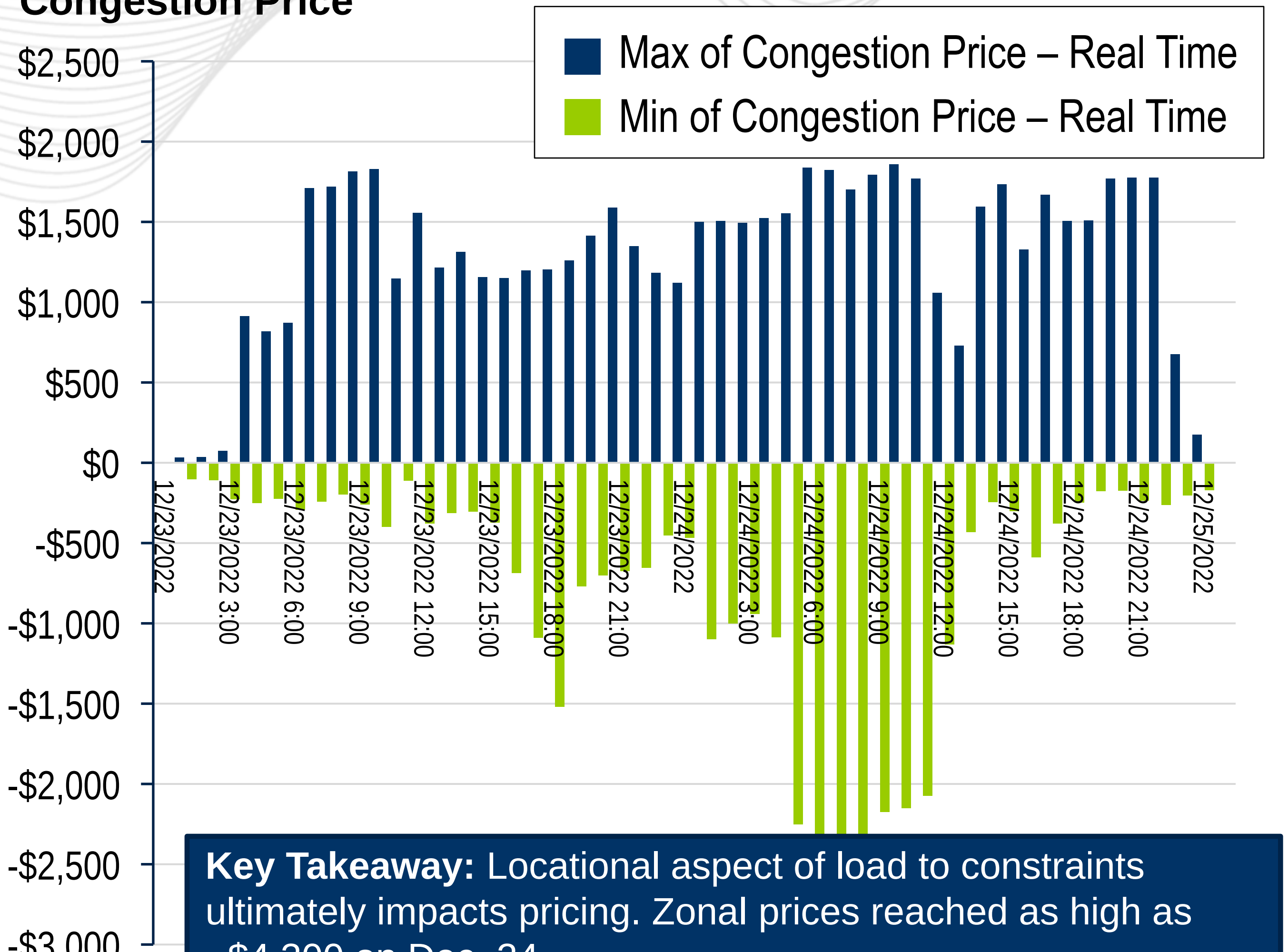
27 of 35 active constraints bound at the transmission constraint penalty factor for at least one 5-min. interval.

Dec. 24

28 of 42 active constraints bound at the transmission constraint penalty factor for at least one 5-min. interval.

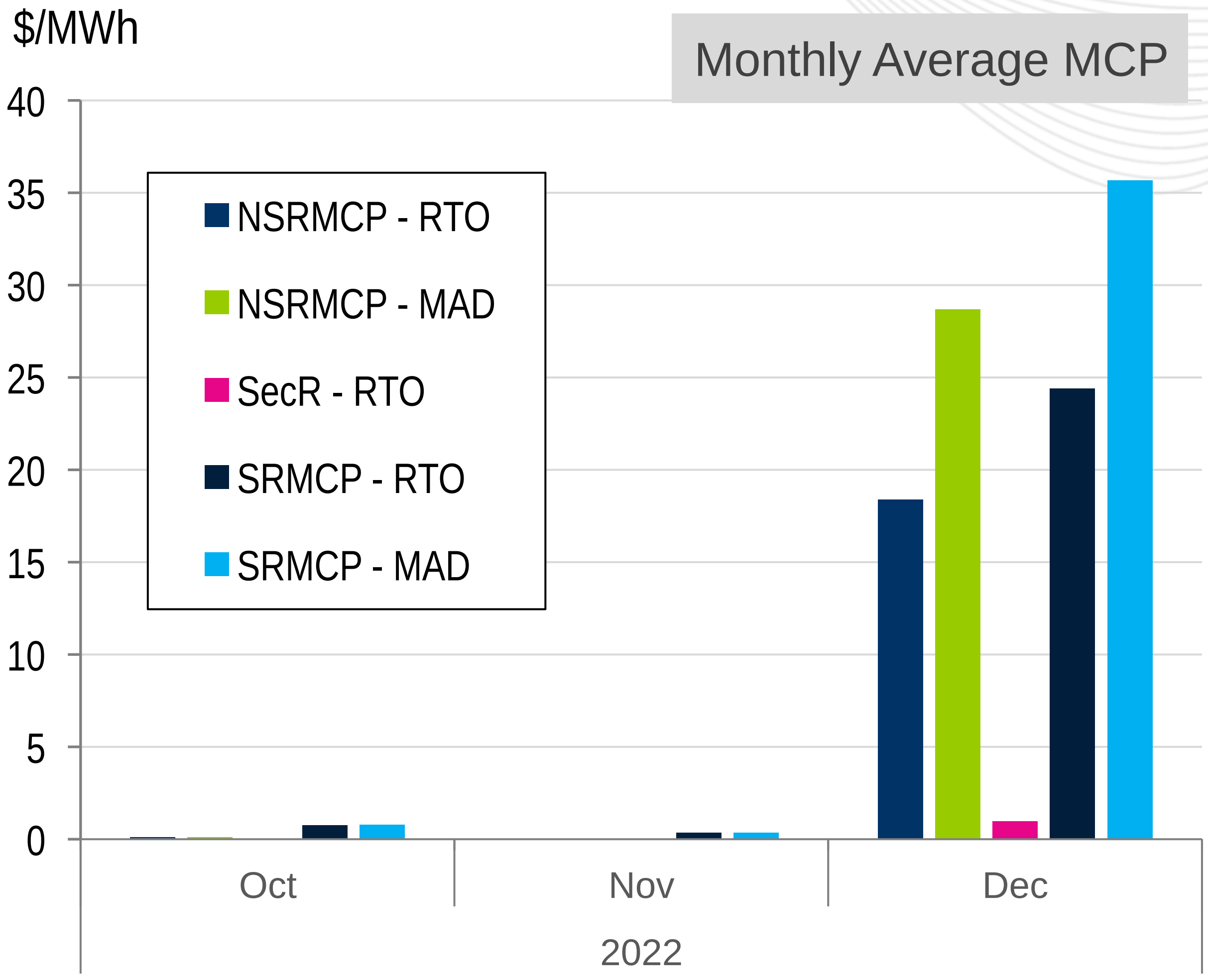
Transmission Constraint Penalty Factors
These are parameters used by the Security Constrained Economic Dispatch (SCED) applications to determine the maximum cost of the re-dispatch incurred to control a transmission constraint. Default is $2,000/MWh.

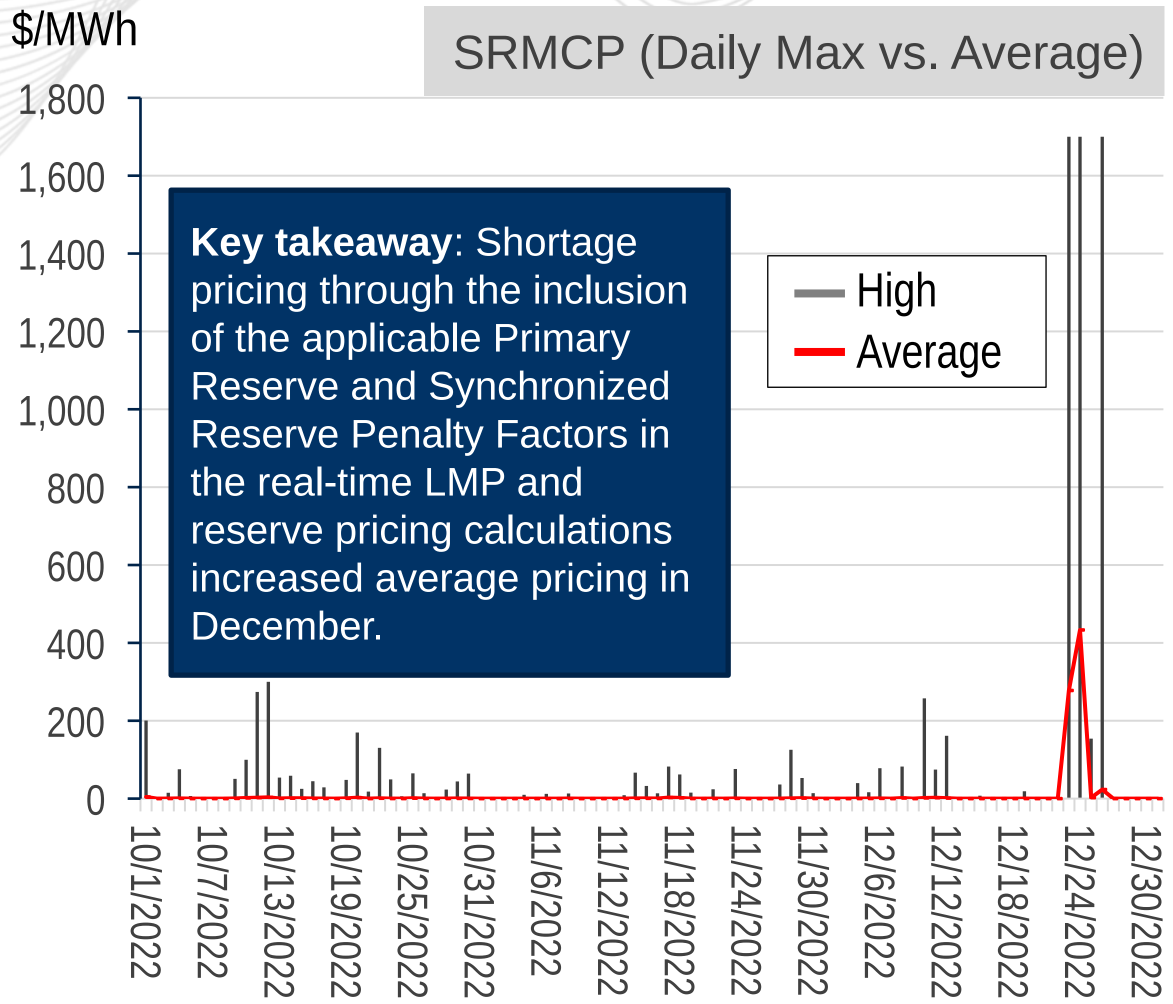
Hourly Min/Max Locational Congestion Price



Key Takeaway: Locational aspect of load to constraints ultimately impacts pricing. Zonal prices reached as high as ~$4,300 on Dec. 24.

Reserve Market Clearing Prices





Key takeaway: Shortage pricing through the inclusion of the applicable Primary Reserve and Synchronized Reserve Penalty Factors in the real-time LMP and reserve pricing calculations increased average pricing in December.

Shortage Intervals – Friday, Dec. 23

71 Shortage Intervals approved by Dispatch

between 16:30 and 22:45.

All intervals reviewed and validated during LMP verification on Dec. 27.

Number of Intervals	Reserve Penalty Factors
45	MAD & RTO – Primary
21	MAD & RTO – Primary & Synchronized
2	MAD & RTO – Primary & RTO – Synchronized
3	RTO Primary

Shortage Intervals – Saturday, Dec. 24

134 Shortage Intervals approved by Dispatch between 00:15 and 16:15.

All intervals reviewed and validated during LMP verification on Dec. 27.

Number of Intervals	Reserve Penalty Factors
69	MAD & RTO – Primary
37	MAD & RTO – Primary & Synchronized
16	MAD & RTO – Primary & RTO – 30-Minute
1	MAD & RTO – Primary & RTO – Synchronized
11	RTO Primary

Load Management Deployment (Pre-Emergency and Emergency Demand Response)

Load Management dispatched for all zones in the RTO.	Deployed and released in tranches (Emergency vs. Pre-Emergency, 30-, 60- or 120-minute lead time, and zone) based on system conditions	
	Dec. 23, 2022 – Approximately **4,000 MW** of capacity deployed	17:30 (first notification) through 22:15 (last release)
	Dec. 24, 2022 – Approximately **7,000 MW** of capacity deployed	04:20 (first notification) through 20:30 (last release)

Load Management is required to consumer at or below the firm service load level. Facility may reduce load or postpone electricity consumption.

PAI Overview

Maximum Generation Emergency Actions Prompted
277 PAI Intervals Across Dec. 23 and Dec. 24

Start	End	# Intervals
Dec. 23, 2022 17:30	Dec. 23, 2022 23:00	**66**
Dec. 24, 2022 04:25	Dec. 24, 2022 22:00	**211**

Affected All Resources in the Entire RTO, Including External Capacity Resources

PAI Actions to Date

Member Communications Sent	During PAI	Timing and cause
	Following PAI	Retroactive replacement transaction information (400 received)
		Preliminary Balancing Ratio information
	Preliminary Balancing Ratios calculated and posted to Data Miner	

Balancing Ratio

The Balancing Ratio is calculated during each Performance Assessment Interval (PAI) to determine each generation capacity resource's obligation to deliver energy.

Balancing Ratio (BR) =

$$\frac{\text{Total Actual Generation and Storage Performance + Net Energy Imports + DR and PRD Bonus Performance*}}{\text{All Generation and Storage Committed Capacity Commitments (UCAP)}}$$

**Note: DR and PRD Bonus Performance are not included in the Preliminary Balancing Ratio due to data submission timelines.*

Preliminary Balancing Ratios

Date/Time	Area(s)	Average BR	Min BR	Max BR
Dec. 23 17:00–23:00	RTO	85.48%	83.00%	86.58%
Dec. 24 04:25–22:00	RTO	80.62%	78.39%	82.73%

Resource Performance Evaluation

Performance is evaluated for each committed capacity resource for each 5-minute interval of a performance assessment event.

Performance Shortfall (per interval) =

Expected Performance	–	Actual Performance	–	Total Excused MW
Committed Capacity MW * Balancing Ratio		Actual Generation + Ancillary Services		• Approved planned or maintenance outages • MW scheduled down due to economic dispatch • MW scheduled down due to manual dispatch

Capacity Resources with a positive Performance Shortfall are subject to a Non-Performance Charge = Performance Shortfall * Non-Performance Charge Rate pjm

Non-Performance Charge Rate for Performance Shortfalls

The Non-Performance Charge Rate is based on yearly Net CONE, a divisor (i.e., an assumed 30 Emergency Action hours per year) and the number of Real-Time Settlement Intervals in an hour.

Charge Rate =

(Net CONE * # days in the Delivery Year) / (30 * 12)

Locational Deliverability Area	Net CONE ($/MW-Day, ICAP Price)	Non-Performance Charge Rate ($/MW-interval)
ATSI	218.79	221.83
ATSI-CLEVELAND	218.79	221.83
BGE	214.87	217.85
COMED	235.27	238.54
DAY	214.82	217.80
DEOK	212.27	215.22
DPL-SOUTH	224.18	227.29
EMAAC	246.18	249.60
MAAC	232.67	235.90
PEPCO	246.34	249.76
PPL	237.69	240.99
PS-NORTH	254.8	258.34
PSEG	254.8	258.34
RTO	247.26	250.69
SWMAAC	230.61	233.81

Note: Non-Performance Charge Rates are calculated for each LDA modeled for the delivery year.

Estimated Non-Performance Charges

PJM's ***rough estimate*** of non-performance charges for Dec. 23 and Dec. 24 is in the $1 billion to $2 billion range.

This estimate is provided as an initial reference point only and can change materially.

It includes preliminary excusals for MW scheduled down due to economic dispatch. It is subject to further change (*increase or decrease*) based on:

- Changes to the final balancing ratio
- Approval of retroactive replacement transactions

- Further review of actual resource performance data
- Further review of excusals due to economic dispatch
- Inclusion of excusals for:
  - Approved planned or maintenance outages
  - MW scheduled down due to manual dispatch

Note: FRR entities could have elected physical penalty in lieu of financial prior to DY.

Bonus Credits: Allocation of Collected Non-Performance Charges

Revenue ***collected*** from payment of Non-Performance Charges is distributed to resources (of any type, even if they are not Capacity Resources) that perform above expectations during each PAI.

- The credit is based on the ratio of its Bonus Performance quantity to the total Bonus Performance quantity (from all resources and PRD Providers for the same PAI).
- Bonus Performance quantity = Actual Performance minus Expected Performance and is capped at the scheduled megawatt quantity.

Billing Timing

OATT Attachment DD, Section 10A

(j)The Office of the Interconnection shall bill charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included such Performance Assessment Intervals, provided, for any Non-Performance Charge, the amount shall be divided by the number of months remaining in the Delivery Year for which no invoice has been issued, and the resulting amount shall be invoiced each such remaining month in the Delivery Year or during the first month of the next Delivery Year if three months do not remain in the current Delivery Year.

- PJM is currently working through the billing timeline to account for any non-payment risk and liquidity concerns.
- Additional information will be provided at the Jan. 24 Risk Management Committee meeting.

Performance Assessment Next Steps

• Review resource performance and excusals	• Retroactive replacement transaction review and approval	• Release of preliminary resource performance data (targeted by first full week of February)
• Demand Response/Price Responsive Demand compliance data submission (due Feb. 14, 2023)		*Dependency for calculation of final balancing ratio*

Michigan Hosting Capacity Study

ITC Michigan
2021

ITC A FORTIS COMPANY | FOR THE GREATER GRID

HOST CAPACITY STUDY - METHODOLOGY

- For convenance and a reasonable means to present the study results, ITC's Michigan systems were assessed using 7 geographic regions (found on slide 6). For each region, a defined number of new generator resources were interconnected at existing substations to assess the capabilities of the system (also found on slide 6).

- The results, found on slides 8 – 14, represented two different system analysis. The "Top 5 highest individual capacities" represents the capability of the transmission system when power is injected at only one of the defined points of interconnection in a single region before major system upgrades are required (each point is assessed independently).

- The "Region Indicative Capacities and Costs" are reflective of the capabilities of the geographic region more holistically. The regions are tested by ramping up the prospective generation units in a region and identifying the major system upgrades required to achieve the targeted injection level (i.e. transfer).

Model Build and Approach

- Analysis for 2025 Summer Peak
  - All MTEP20 approved projects
- 225 points of interconnections examined
  - Existing >100kV stations with 3 or more transmission line connections
- Transfers studied at selected stations up to:
  - 1,000 MW for 120kV, 138kV and 230kV
  - 3,500 MW for 345kV

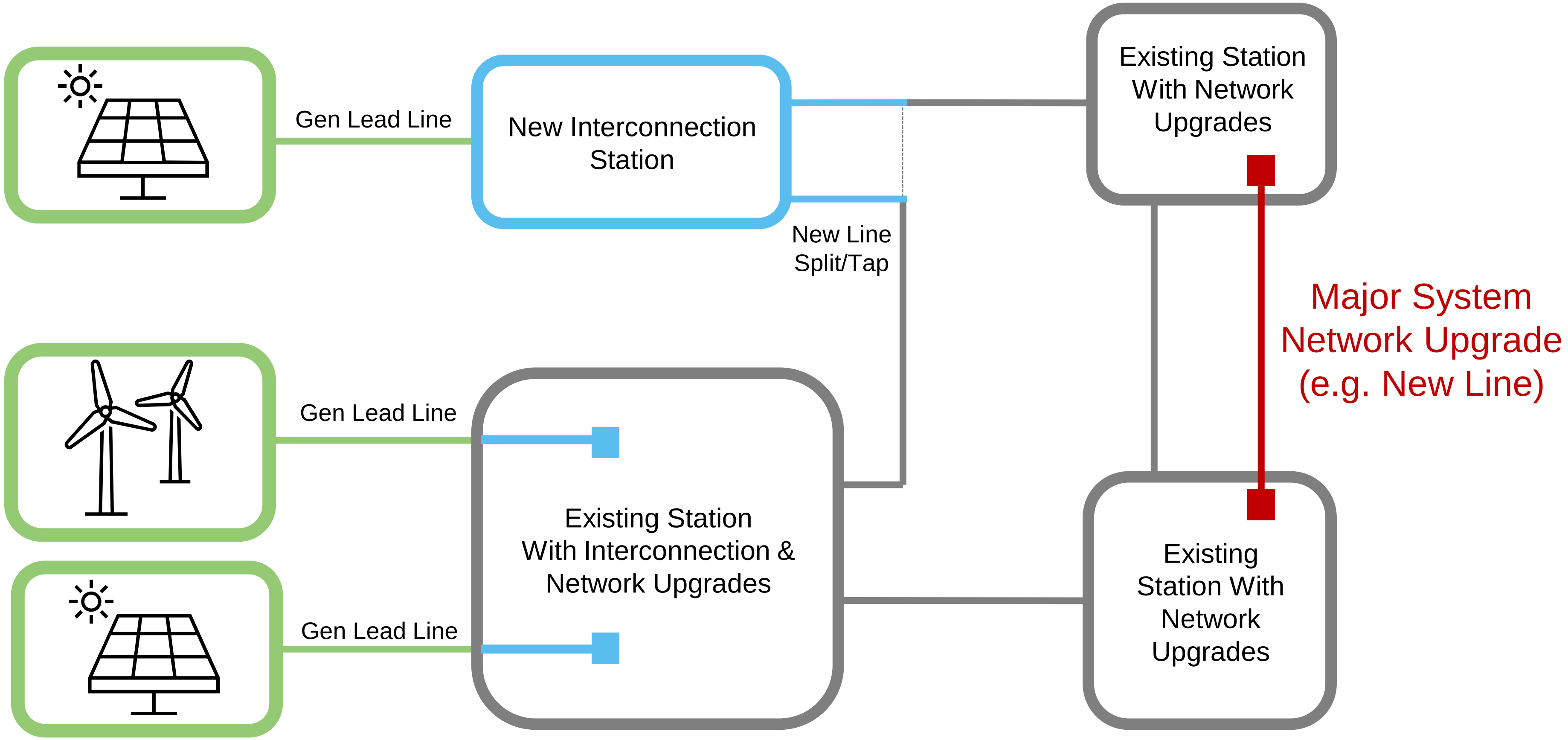
HOST CAPACITY STUDY – DISCLAIMER(S)

- The system network upgrade costs developed are indicative **estimates** for **major system-upgrades** (including conductors and/or transformers) from steady-state analysis only. The costs **do not** include any **interconnection facilities** (i.e. direct assign or network upgrades) that may be identified (The next slide provides a visual representation). Actual interconnection facilities and NRIS/ERIS network upgrade costs for new generators connected to the ITC & METC systems must be determined by completing the MISO and ITC interconnection process.
- The analysis was performed prior to recently submitted Consumers Energy Integrated Resource Plan (CE IRP). Proposals in the CE IRP, or other major system changes, could alter findings and result in different levels of expected capacity and indicative costs.

EXCLUDED VS INCLUDED INDICATIVE COSTS

These Types of Interconnection Facility (Direct Assign and Network Upgrade) Costs are **EXCLUDED** in Analysis Indicative Costs

These Types of Network Upgrade (NRIS/ERIS) Costs are **INCLUDED** in Analysis Indicative Costs



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MICHIGAN STUDY REGIONS

Northern Michigan

- 345 kV: 4 stations
- 138 kV: 23 stations

Midland

- 345 kV: 6 stations
- 138 kV: 23 stations

Central

- 345 kV: 10 stations
- 138 kV: 21 stations

South

- 345 kV: 6 stations
- 138 kV: 21 stations

Thumb

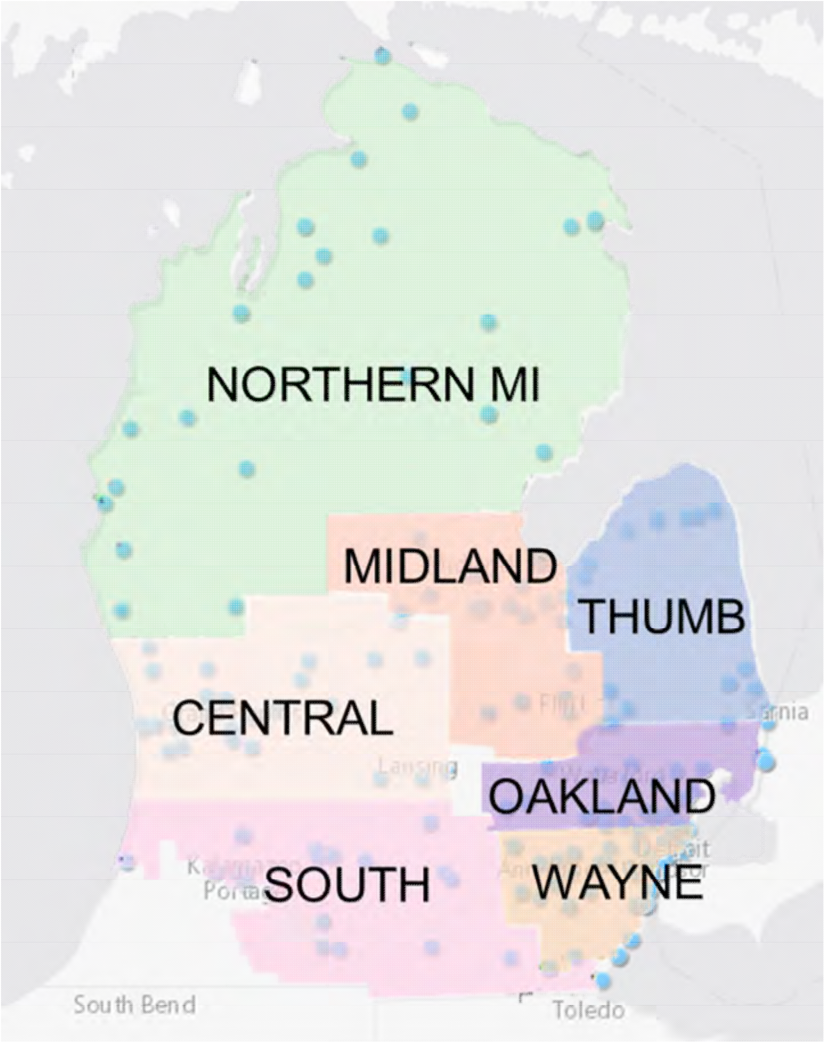
- 345 kV: 8 stations
- 120 kV: 11 stations

Oakland

- 345 kV: 14 stations
- 230 kV: 1 station
- 138 kV: 18 stations

Wayne

- 345 kV: 10 stations
- 230 kV: 5 stations
- 138 kV: 44 stations



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MICHIGAN REGION INTERACTIONS ON CAPABILITY

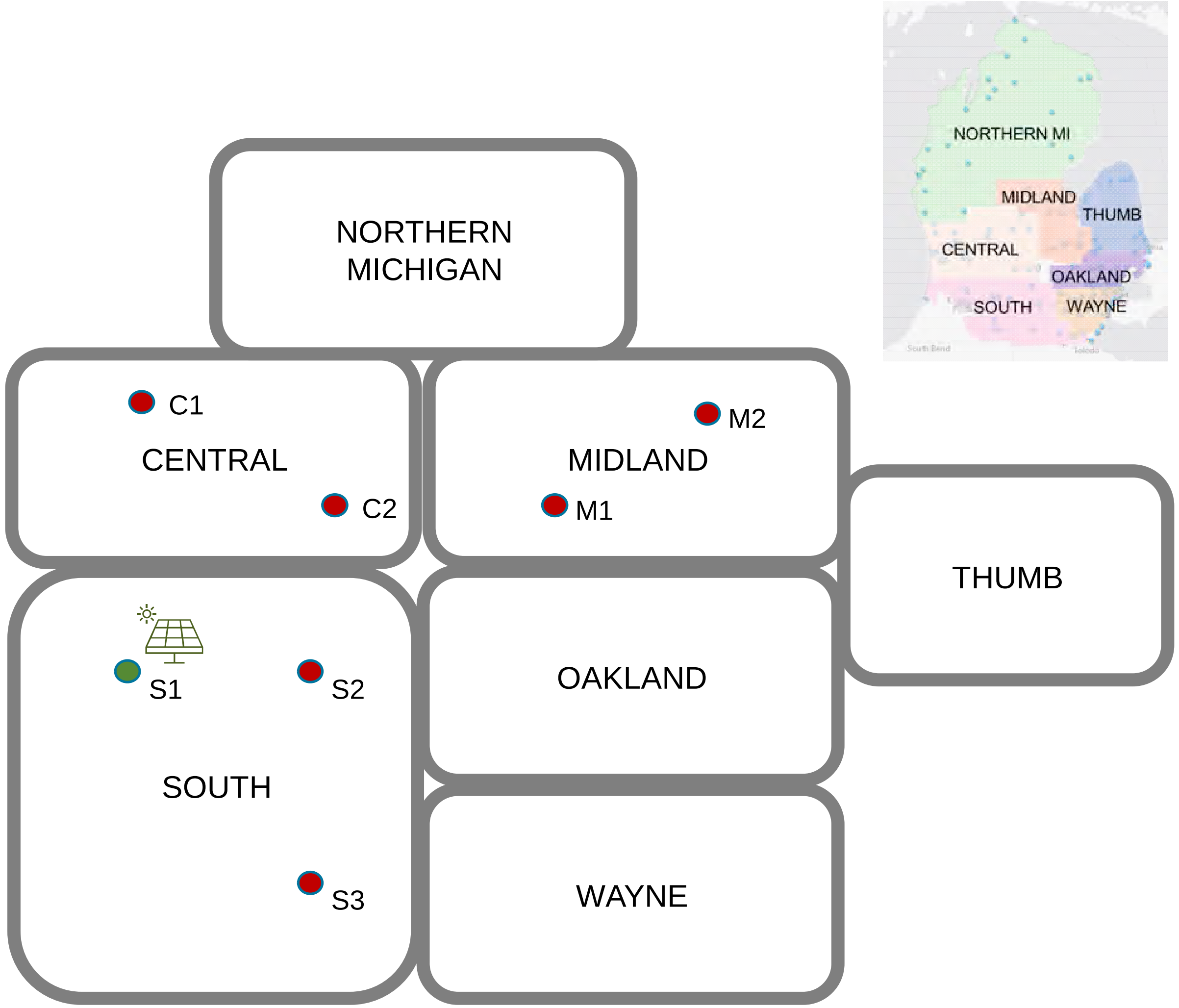
Available capacity in the system is shared…

- within each region and…
- across each of the Michigan regions.

…therefore, <u>indicative capacity is not cumulative</u>

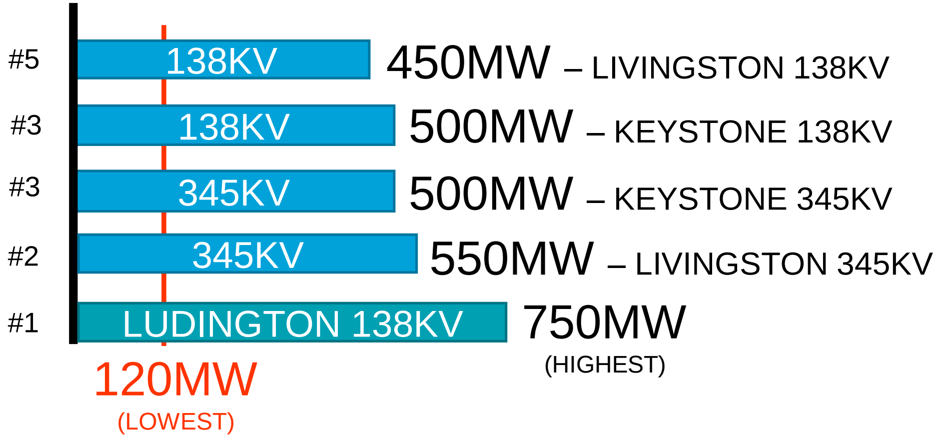
EXAMPLE (Hypothetical): 500MW new generation interconnects at South location S1 resulting in…

- S2 and S3 *future capacity* decreasing
- C1, C2, M1 and M2 *future capacity* decreasing

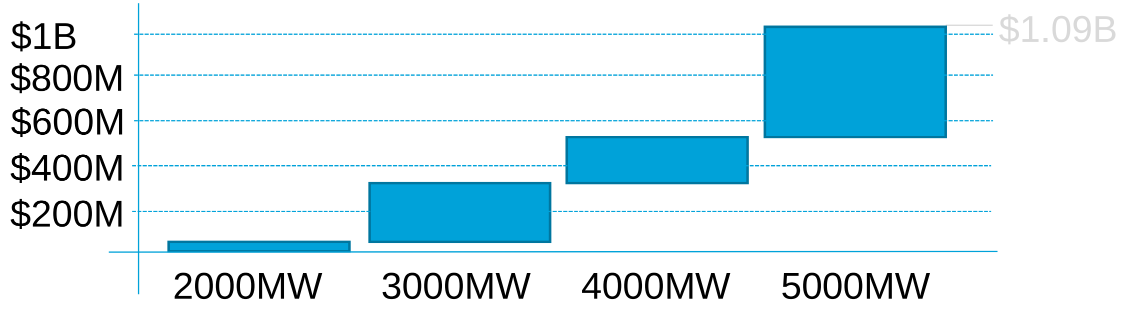


NORTHERN MICHIGAN REGION

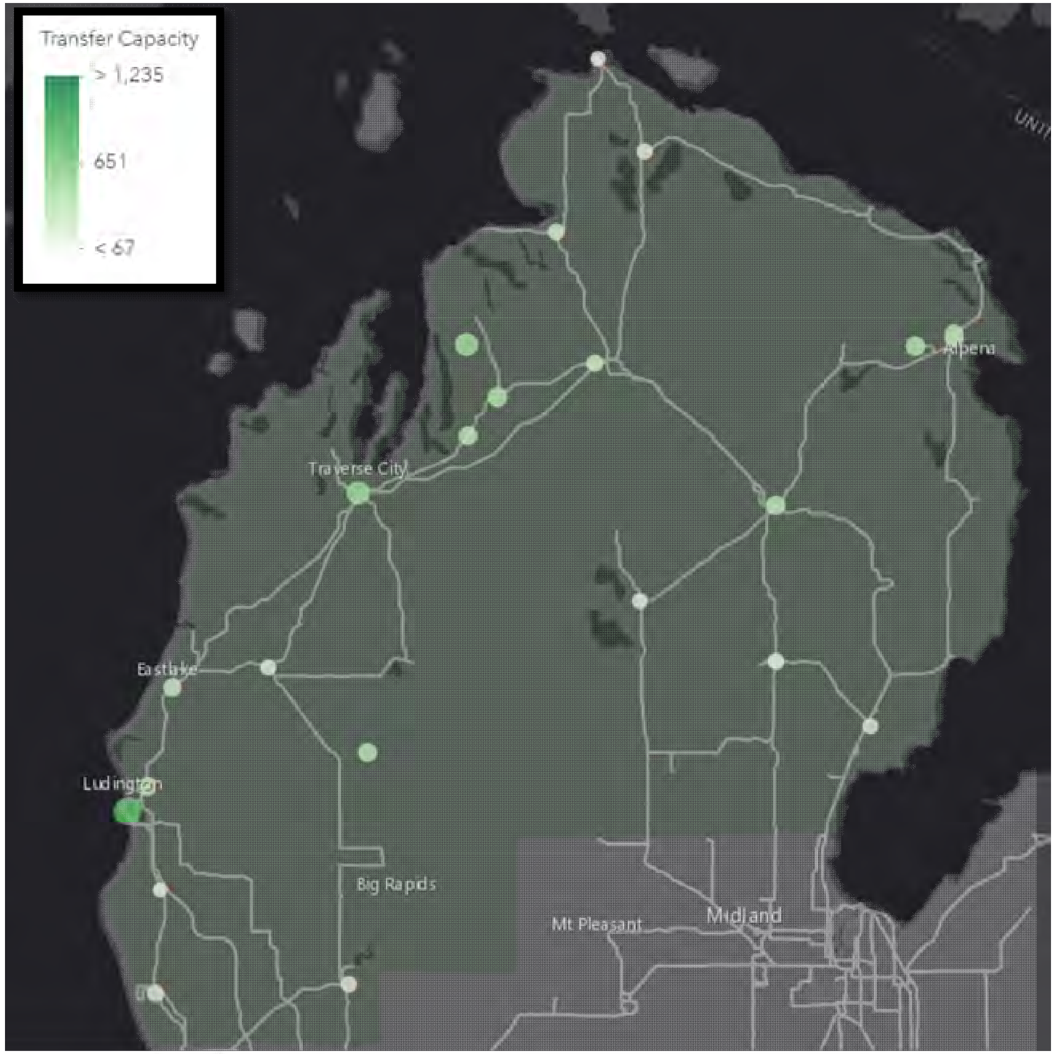
Top 5 highest individual capacities



Region Indicative Capacities & Costs*



*Costs are subject to previous disclaimer



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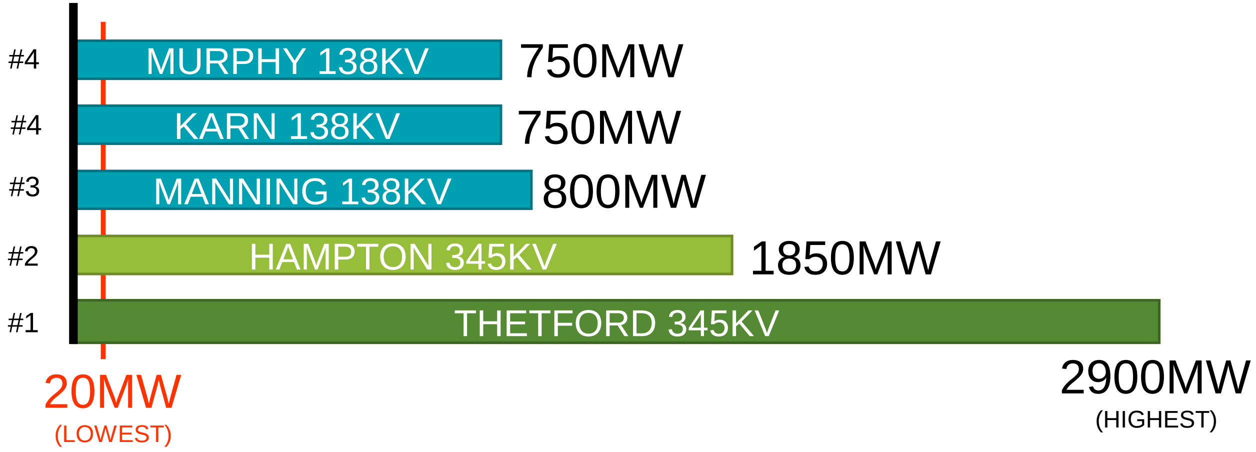
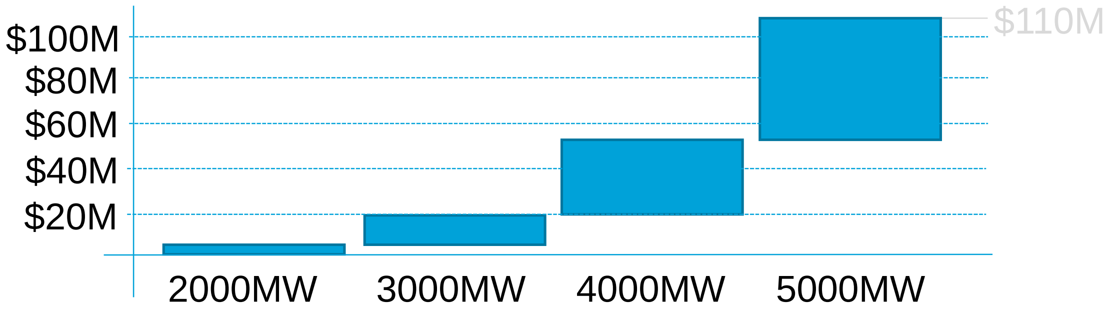
MIDLAND REGION

Top 5 highest individual capacities



Region Indicative Capacities & Costs*



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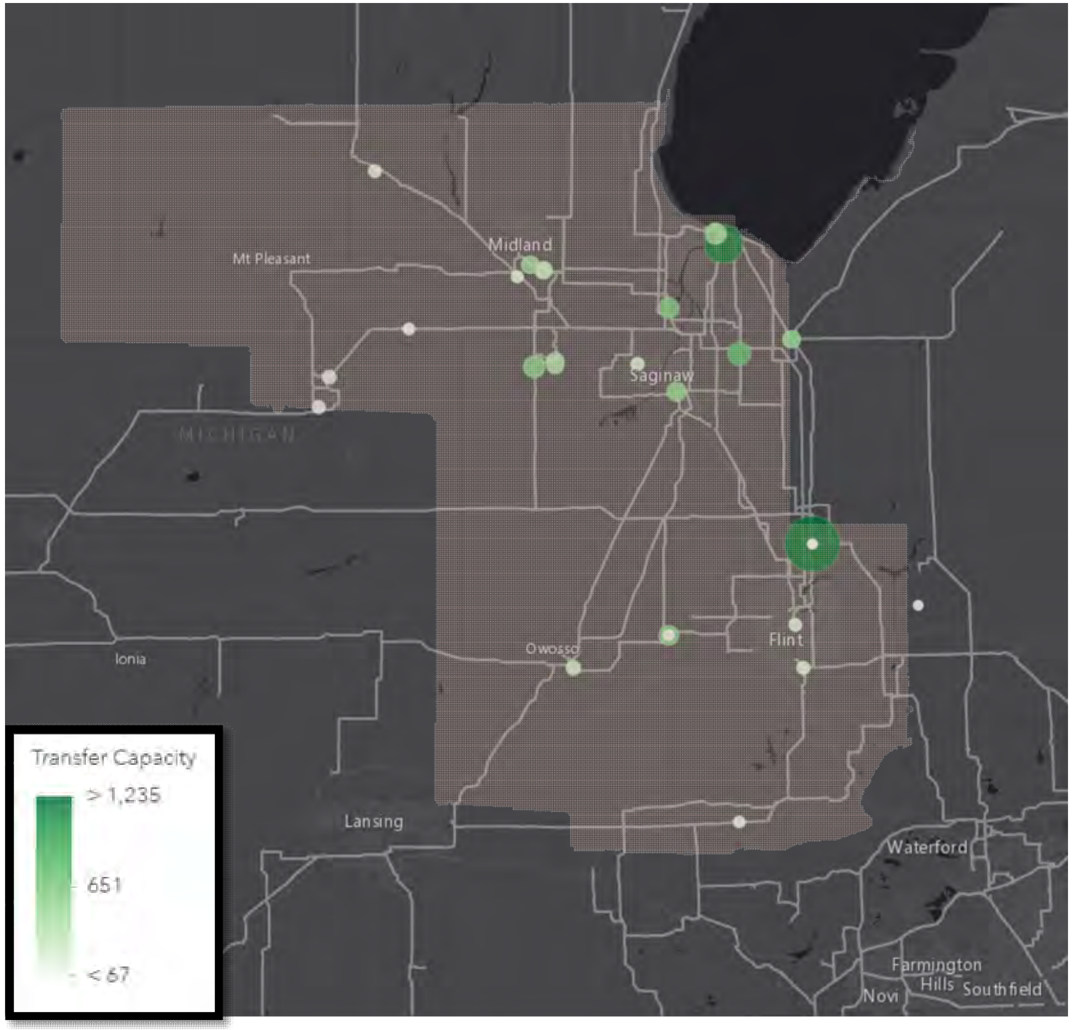

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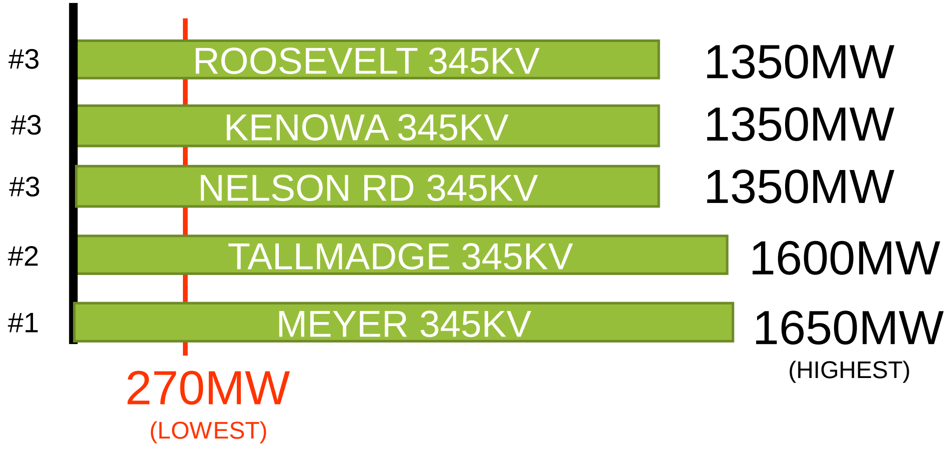
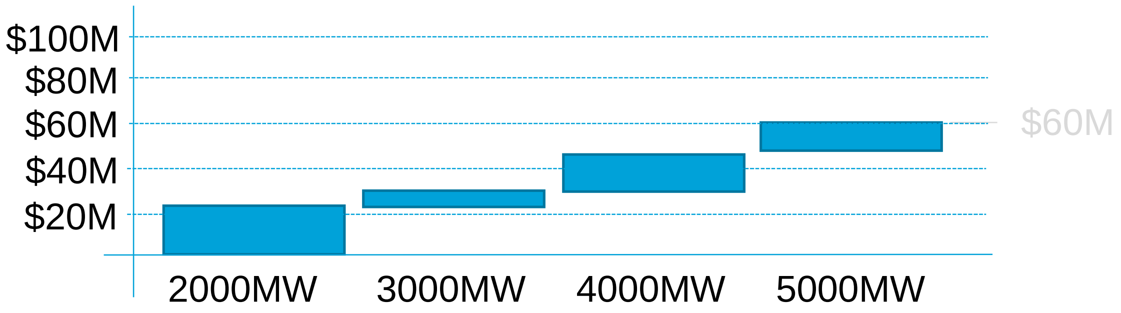
CENTRAL REGION

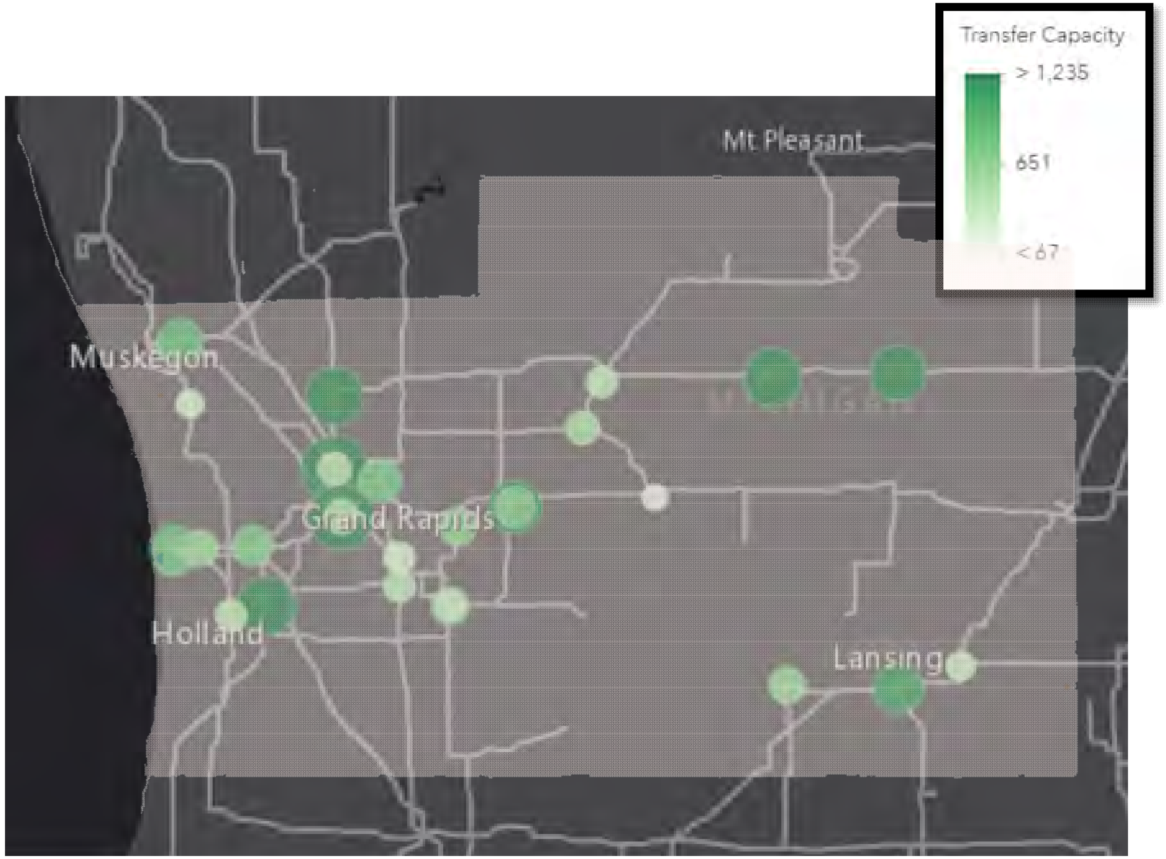
Top 5 highest individual capacities



Region Indicative Capacities & Costs*



*Costs are subject to previous disclaimer



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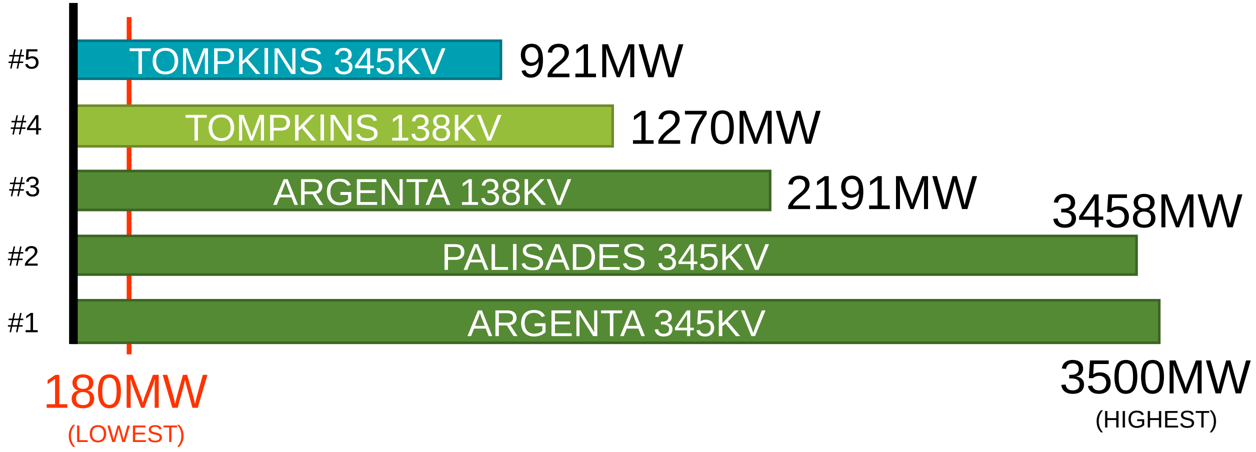
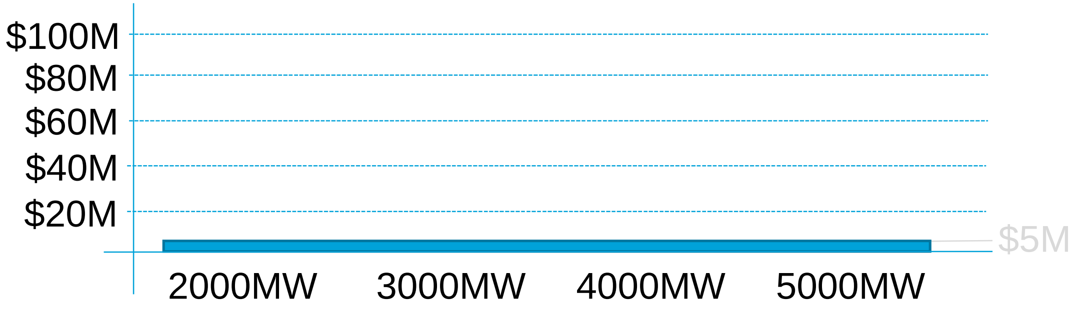
SOUTH REGION

Top 5 highest individual capacities



Region Indicative Capacities & Costs*



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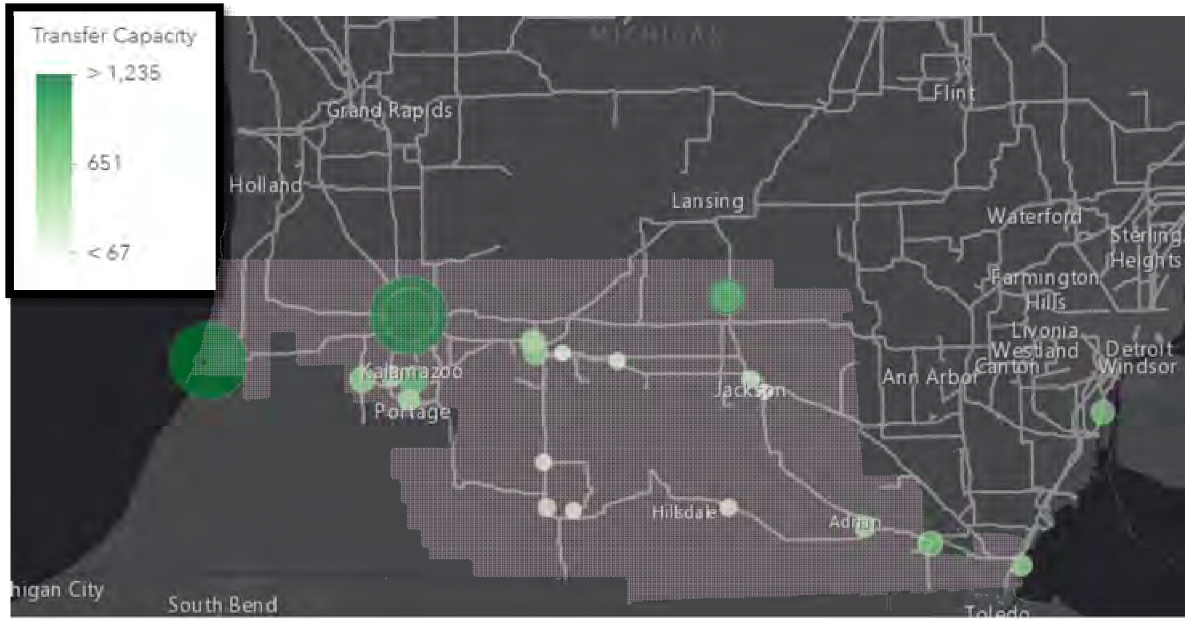
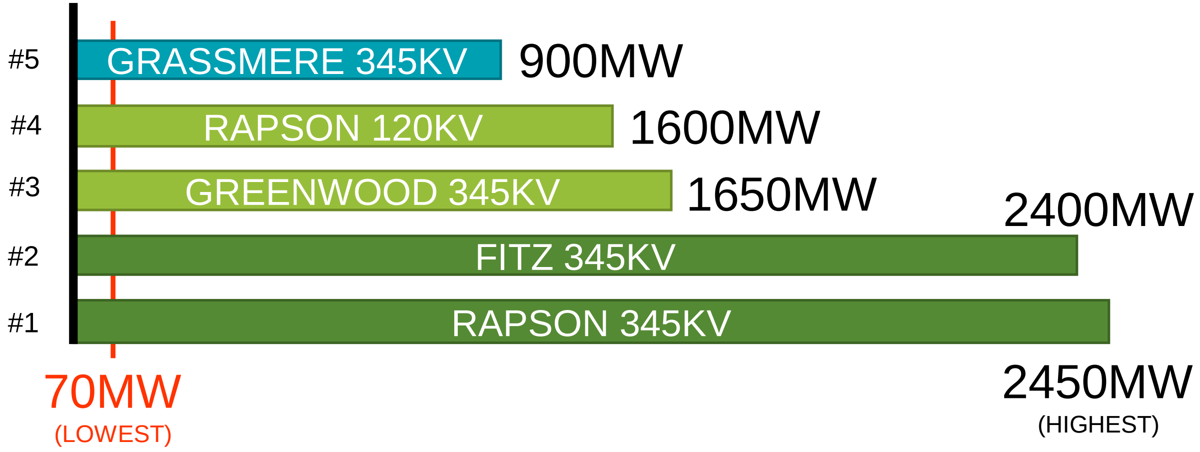
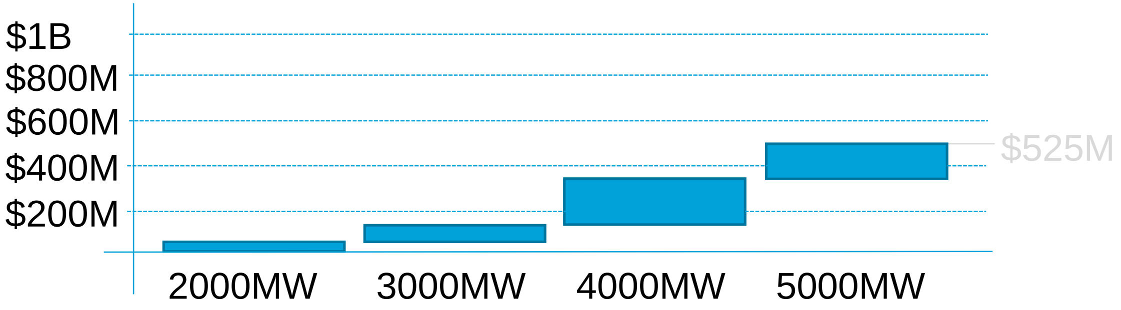


THUMB REGION

Top 5 highest individual capacities



Region Indicative Capacities & Costs*



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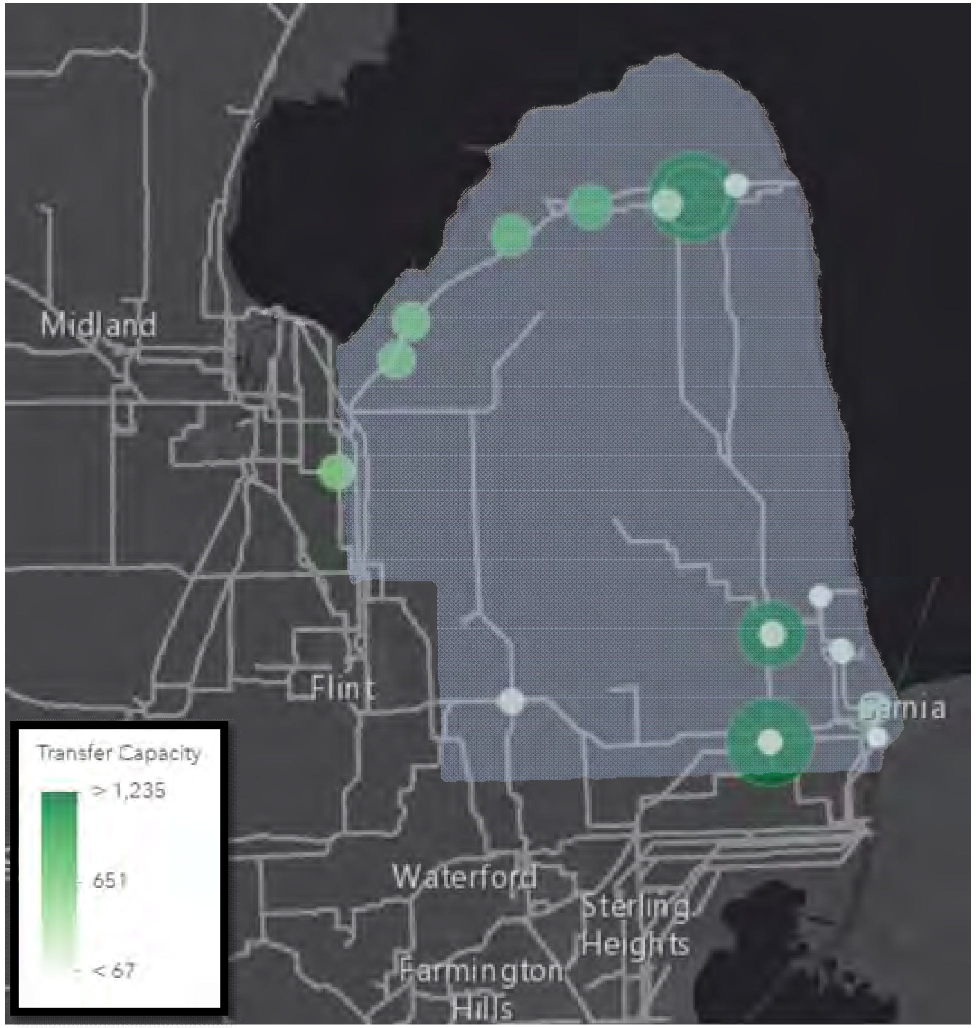

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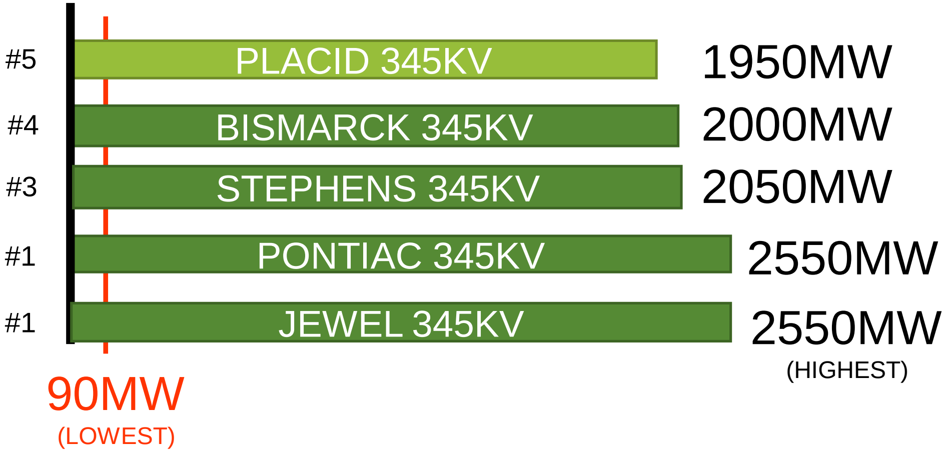
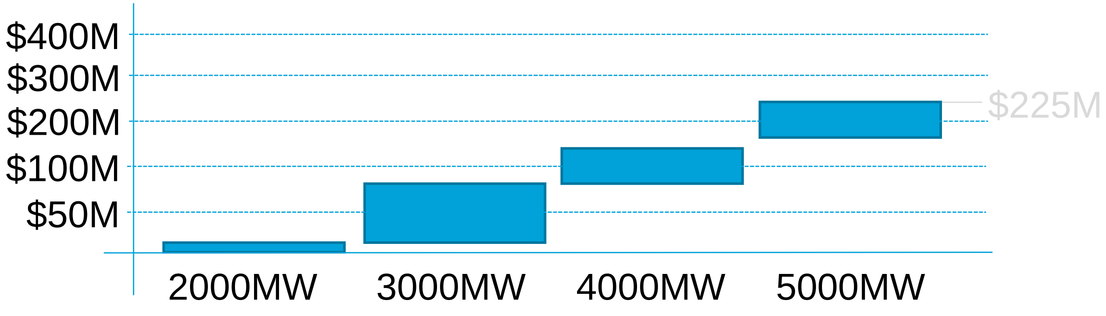
OAKLAND REGION

Top 5 highest individual capacities



Region Indicative Capacities & Costs*



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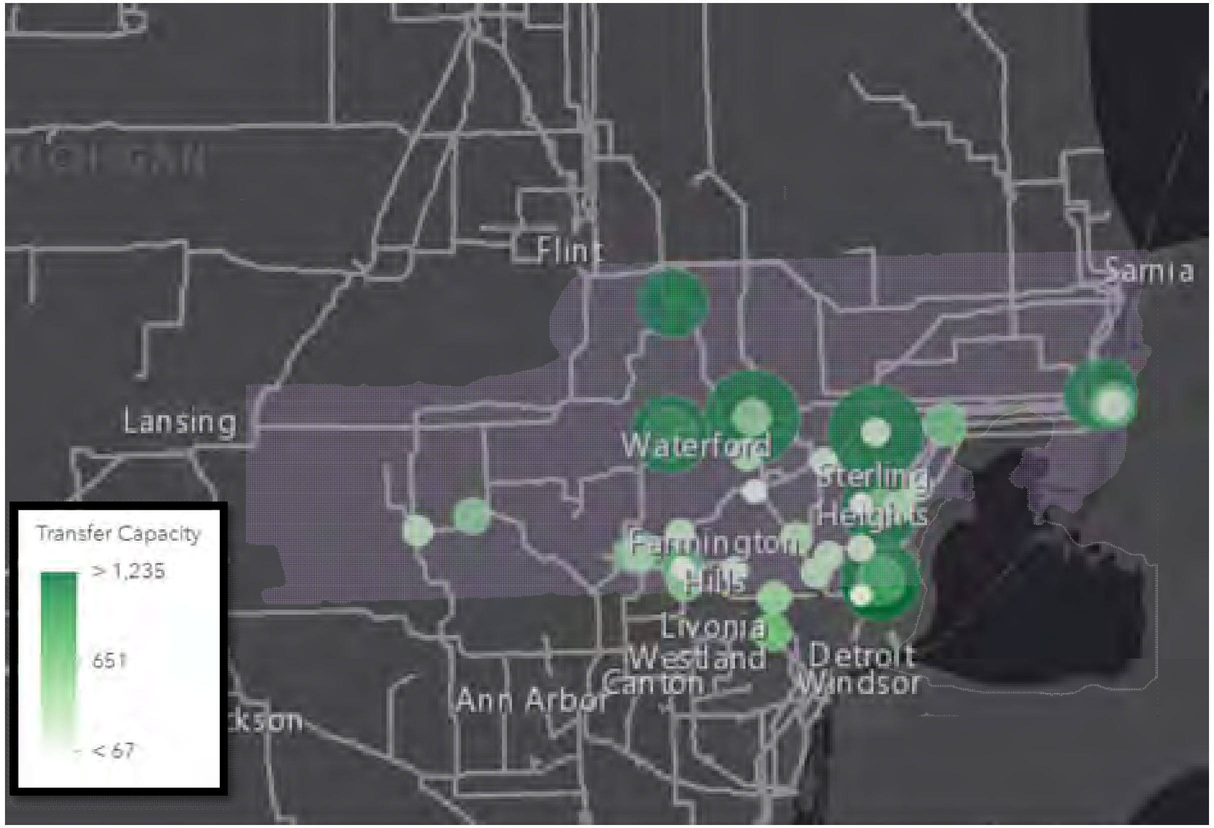
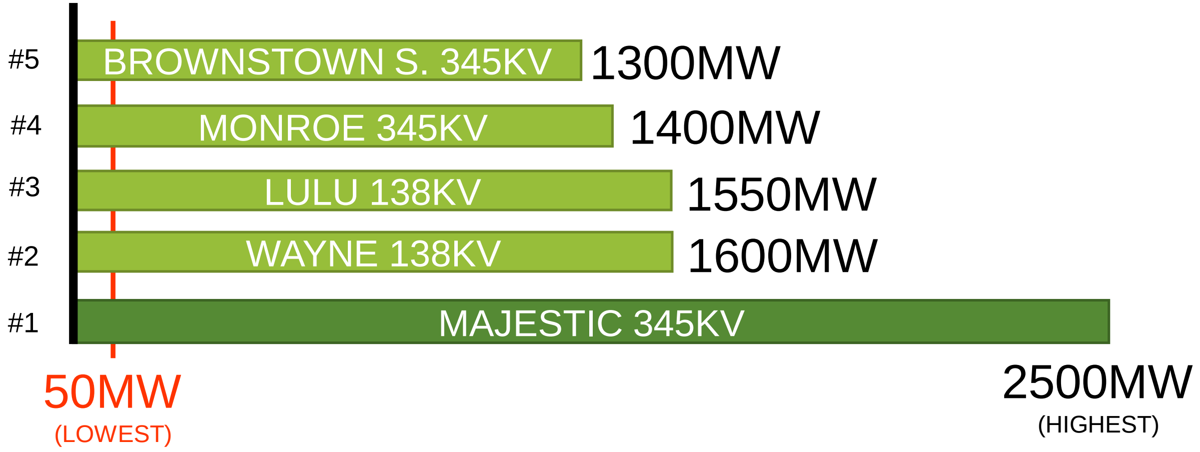
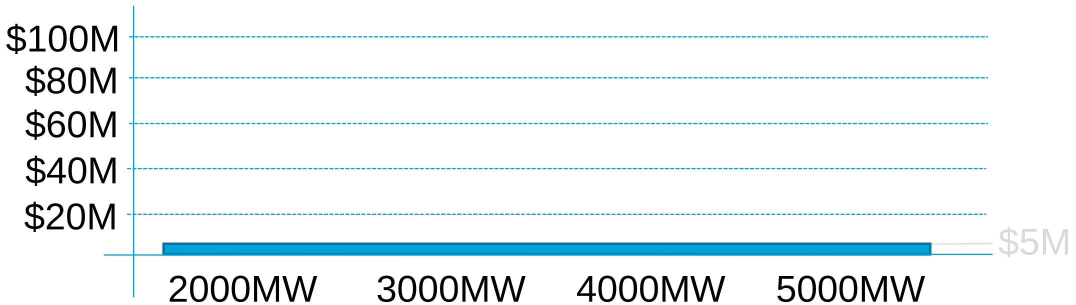


WAYNE REGION

Top 5 highest individual capacities



Region Indicative Capacities & Costs*



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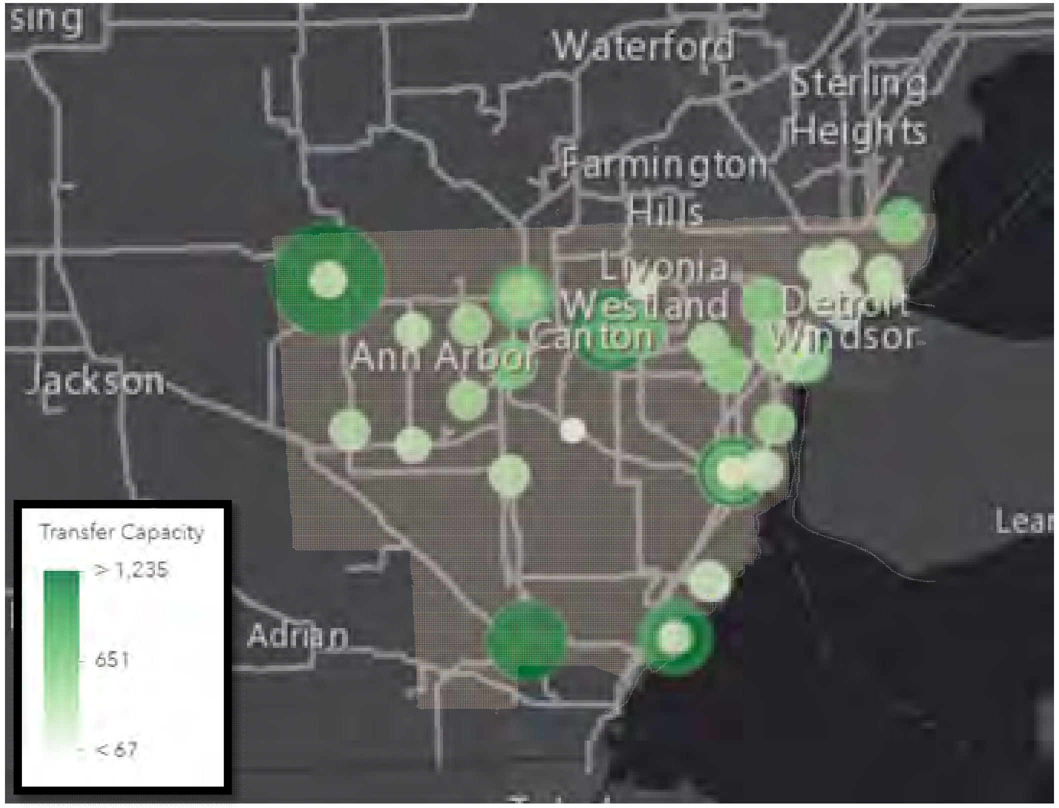

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Partners in Business

The Host Capacity Study will be presented at the partners in business meeting on October 19, 2021.

https://www.itc-holdings.com/op/itc-michigan/michigan-partners-in-business

Beyond Wires

Using Advanced Transmission Technologies to Accelerate the Transition to Clean Energy

ENVIRONMENTAL LAW & POLICY CENTER

Table of Contents

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Introduction

As renewable energy expands nationwide, we need a robust, efficient, and modern electricity delivery network to match. By enhancing the performance of our existing transmission system with smart technology, we can maximize clean energy investments, reduce carbon pollution, and improve reliability. Advanced transmission technologies, such as battery storage, dynamic line rating, and power flow control add digital intelligence to analog wires, to unlock gigawatts of new transfer capability and bring renewable projects online. Paired with local distributed energy solutions and non-transmission solutions, these grid investments can relieve congestion to get renewables onto the grid faster and cheaper than relying on new transmission lines alone.

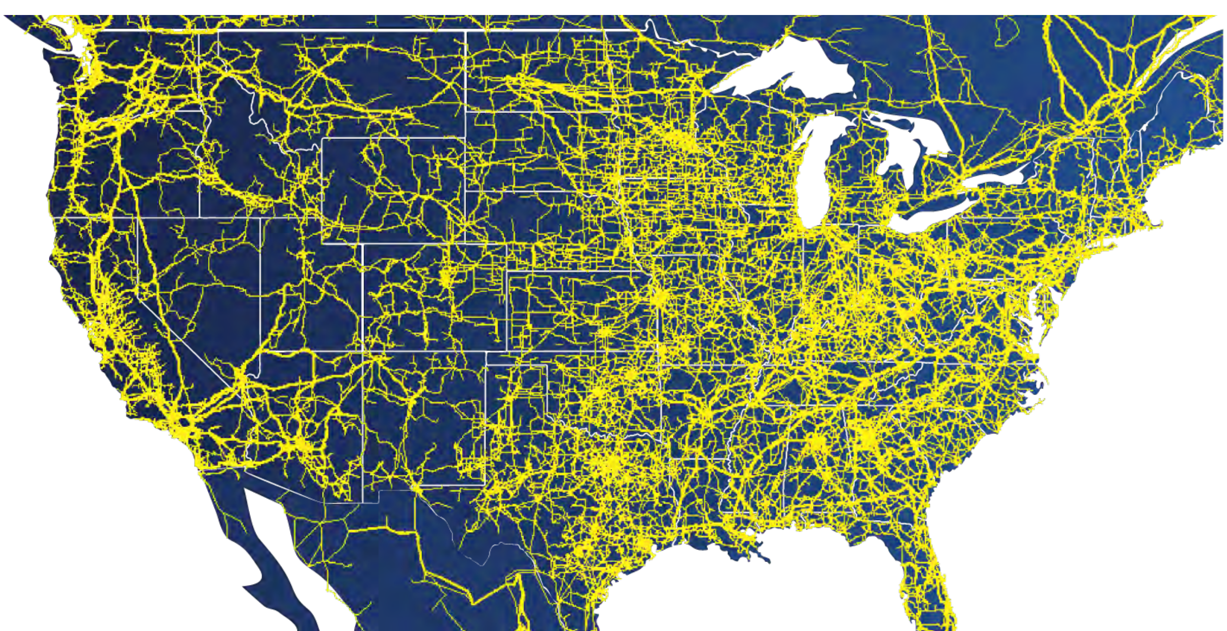
To be clear, this is not an "either/or" choice between traditional large wires projects and new transmission technologies. Both are critical. However, much of the US is already blanketed by underutilized transmission lines, while planners and transmission owners largely ignore lower-cost solutions that can help unclog existing transmission capacity. This puts the transition to clean energy in jeopardy.

The barriers are not the lack of technology, nor its cost. The underlying problems are regulatory. While federal regulators have pushed to open markets and improve fair competition, the reality is that implementation continues to favor entrenched monopolies and the highest-cost solution. This discriminatory treatment of competitive non-wires technologies has led to unjust and unreasonable rates, in violation of the Federal Power Act. New rules are necessary to encourage investments in the best technology now and into the future. Especially as the Biden administration and Congress map out new energy infrastructure opportunities, it is critical to ensure wise investments in an efficient and holistic energy system, including and beyond wires. A combination of legal and expert intervention is required to achieve the electricity delivery system we need.

The Environmental Law and Policy Center (ELPC) is collaborating with the Center for Renewables Integration (CRI) in a three-pronged approach to grid transformation. Building on the work done by others at the Federal Energy Regulatory Commission (FERC), our Beyond Wires campaign works to ensure that transmission- and distribution-connected technologies are fully considered and optimally deployed to maximize cost-effective electricity delivery and renewables interconnection. With a combination of legal and expert intervention, we can achieve the electricity delivery system we need.

> **"This is not an 'either/or' choice between traditional large wires projects and new transmission technologies. Both are critical."**

Transmission Lines Across the U.S.



Mobilizing Technology to Maximize Grid Performance

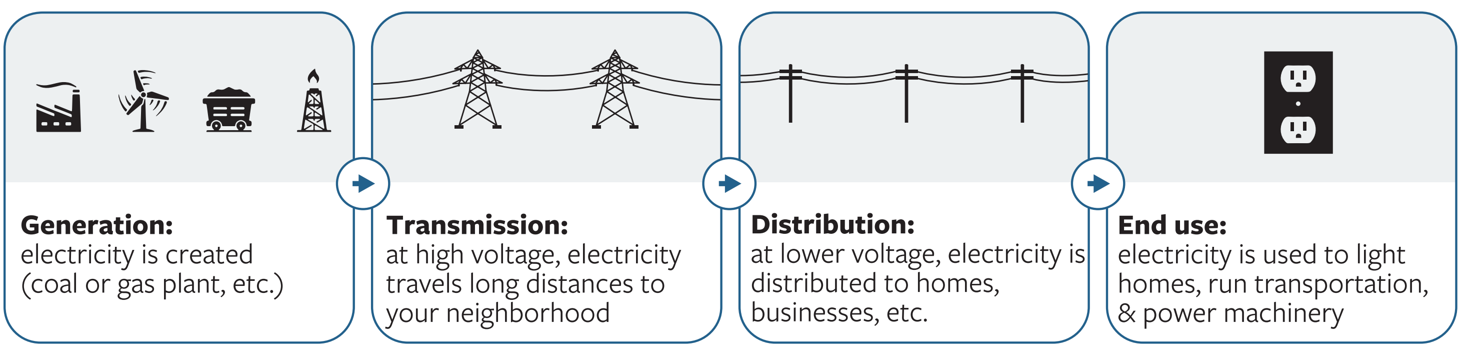
The flow of electricity on transmission lines is limited by the physical properties of wires and other hardware. If you exceed the limits, transmission lines will overheat or fail in other ways. In most of the U.S., power flows across a combination of smaller and larger transmission lines. The limits on small lines can clog up the transmission system, leaving larger transmission lines significantly underutilized. It is the electrical equivalent of a wide water pipe connecting to a narrow one. When the wide pipe is carrying a large amount of water, the connection to the narrow pipe can cause water to backup and flood. There are solutions to avoid flooding, such as connecting multiple narrow pipes to the large one, or using pumps to accelerate water through these additional smaller pipes. Similarly, technology can widen or redirect clogged points on the transmission system.

There are three options to increase transmission capacity: building new transmission lines, using technology to unlock underutilized capacity, and developing local energy generation to fill needs at peak times, under the control of grid operators. Many parties are pursuing the first option, but building new transmission can easily take a decade. Wind and solar projects are already encountering major delays and increasing costs to connect to the grid. The U.S. needs to use all available transmission technologies—not just new wires—to ensure growing interconnection delays don't turn into a crisis.

FERC and other transmission experts use an alphabet soup of acronyms to describe non-traditional transmission solutions. FERC defines grid-enhancing technologies (GETs) broadly as "technologies that increase the capacity, efficiency, or reliability of transmission facilities." FERC Order 1000 addresses "alternative transmission solutions" (ATS) that can be comprised of "advanced transmission technologies" (ATT) as defined in the Federal Power Act. Some states require consideration of "non-transmission alternatives" (NTA) and FERC recently accepted a proposal by MISO to allow "storage as a transmission-only asset" (SATOA).

While there are nuances between these definitions, for the purposes of this paper we will refer to this entire suite of technologies that can provide transmission solutions as "advanced transmission technologies" or ATTs. These transmission technologies are not limited to facilities on the bulk transmission network. Distribution connected assets—such as distributed generation, storage, load control, and energy efficiency—can serve as advanced transmission technologies if they are designed and controlled to relieve transmission constraints.

Traditional Grid Terminology



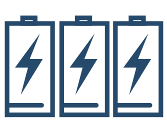
Historically, energy flowed in one direction, through a distinct chain of authorities. But today the grid is changing to embrace new renewable technology. Energy can now be created, stored, and managed at multiple points throughout the grid, offering new opportunities for flexible, decentralized, and efficient electricity delivery.

Advanced Transmission Technologies Are Rapidly Emerging as Viable and Cost-Effective Transmission Solution

Battery storage is perhaps the most flexible technology on the market today, and it can improve transmission in many ways. For example, storage can be sited in a transmission-constrained zone and used to provide voltage support in case of a fault on a line or as a backup solution to ensure reliability while repairs are executed. It can be used to reduce peak loads, increase capacity on congested lines, direct the power flow away from lower capacity transmission lines, and control the timing of power flows to remain under thresholds. With energy storage, utilities can defer investments as supply and demand patterns change, allowing them to avoid all-in, 50-year investments in favor of shorter-term flexibility. Finally, storage can provide energy, capacity, and ancillary services when not being used as a transmission asset. And it can do all of this in deployment times much lower than traditional infrastructure, and increasingly at a lower cost.

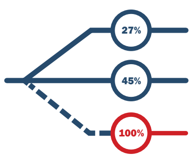
For example, in Germany, grid operators have ordered the construction of 900 MW of batteries to boost existing transmission lines and reduce the need for expensive, highly contested transmission lines. In Australia, officials are considering a “virtual transmission line” consisting of two large (250MW/125MWh) battery-based energy storage systems that will provide additional transfer capability of the existing transmission system.

Grid-Enhancing Technologies (GETs)



Battery Storage – Stores energy anywhere along the grid, ready when needed. Adds flexibility, capacity, and reliability, while reducing energy congestion.

Dynamic Line Rating – Automatically adjusts how much power a transmission line can carry based on real-time weather conditions, to increase efficiency and reduce overload outages.



Power Flow Control – Redirects power flows away from low-capacity lines to avoid creating bottlenecks, like the “WAZE of the transmission system.”

In addition to battery storage, FERC is taking a close look at other “grid enhancing technologies” (GETs) such as advanced line rating management systems and power flow control and transmission switching equipment. Dynamic line rating allows transmission operators to automatically adjust how much power a transmission line can carry based on real-time weather conditions. Instead of keeping lines limited to suit the safety needs of the most inclement conditions, operators can limit capacity just as needed, and increase power more consistently. These adjustments can significantly increase the effective capacity of existing and future lines and allow the system to operate at lower cost without the addition of new infrastructure.

Finally, power flow controls direct the flows of electricity on transmission lines. Coined the “WAZE of the transmission system,” power flow technology redirects power flows to avoid creating bottlenecks, staying off low-capacity lines. In the UK, National Grid Electricity Transmission installation of power flow control technology will increase system capacity by 1.5 GW.

While these are a few of the most promising FERC-defined GETs available today, the list is by no means exhaustive and is only going to grow as technologies improve. FERC has recently taken an interest in GETs and has an ongoing investigation into GETs compensation, installation, and use.

> **“These adjustments can significantly increase the effective capacity of existing and future lines.”**

Advanced Transmission Technologies can Postpone or Replace the Need for New High-power Lines

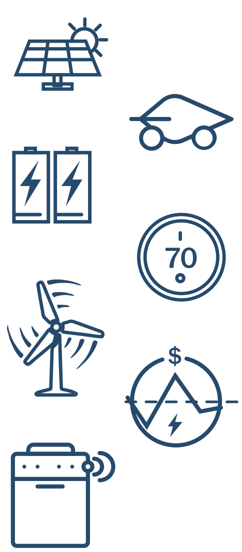
The distribution side of the grid also offers opportunities to reduce energy congestion and improve electricity delivery. For example, community solar panels and other distributed generation (DG) solutions create energy close to where it will be used, reducing the need to send energy through the transmission grid in the first place. Demand response (DR) programs balance energy supply and demand by encouraging customers to reduce or shift their energy use away from peak times. Energy efficiency (EE) helps people do more with less electricity, and battery storage adds flexible energy throughout the grid. Storage on the distribution side can provide load balancing and act as generation when needed. When technologies and programs like these (collectively, distributed energy resources or DERs) are deployed intentionally, they can solve transmission needs in lieu of a new high-power line.

Unfortunately, transmission planners rarely consider the potential for DER in the transmission planning process. Distributed energy resources are usually just factored into estimates of future load growth and rarely considered as a solution to a transmission need. Transmission operators should compensate (and cost allocate) DERs as transmission assets if they are built and controlled to solve a specific transmission need (such as an overload on a specific line). For example, consider a prescribed quantity of battery storage assets (e.g., 120 MW / 480 MWh) and demand response technologies located in a zone served by a transmission line that is expected to exceed reliability limits. These distribution-connected assets can be controlled in a manner that specifically reduces load on the transmission line (e.g., demand response is activated, or batteries are discharged, during summer peak hours, in accordance with a signal from the utility). Federal law specifically allows this scenario by designating these technologies as Advanced Transmission Technologies and requires FERC to determine how to encourage their use, by identifying means of folding these solutions into the planning process and developing compensation structures.

As real-world examples, in Oakland, PG&E will implement a solution consisting of storage, distributed generation, and infrastructure upgrades rather than build new transmission lines. Bonneville Power Administration cancelled a 500 kV transmission line designed to serve load in Portland-Vancouver, replacing the line with local storage and flow control. These DER technologies are providing transmission solutions.

Not withstanding their federal mandate, grid operators have been slow to deploy non-wires technologies to provide transmission services. We simply aren't using all the tools available to unclog the transmission system. Historically, the legal chasm between the local distribution system (managed by states) and the interstate transmission system (managed by FERC) has prevented optimal deployment of distributed-connected assets to provide transmission services. However, FERC Orders 845 and 2222 are beginning to bridge this gap by requiring regional independent service operators and regional transmission organizations (ISO/RTOs) to allow energy storage and distributed energy resources to participate in markets. While participating in markets is not the same as operating as a transmission asset, FERC's orders create an important precedent by enabling regional grid operators to communicate with and control DERs on the distributed system. This is a fundamental requirement for DERs to be considered a transmission asset.

Distributed Energy Resources (DERs)



- **Distributed generation, like rooftop & shared solar panels**
- **Electric vehicles**
- **Battery storage**
- **Smart inverters, meters, thermostats, etc.**
- **Demand Response**
- **Energy Efficiency**
- **Microgrids**

> **"We simply aren't using all the tools available to unclog the transmission system."**

Wires-Only Solutions are Insufficient to Meet Our Nation's Ambitious Clean Energy Goals Alone

Building new transmission is expensive, time consuming, and logistically difficult. While we will continue to need new transmission lines, building large infrastructure is not the best way to address every energy situation on the timeline that the Biden administration and others know is necessary to meet our climate challenges. Relying on wires-only solutions ignores the many other tools available to meet our transmission needs and makes it more difficult to transition to a clean energy economy.

Poles and wires transmission line projects can take years, if not a decade to plan, approve, and construct. That is especially true for large, high voltage lines. In the meantime, interconnection queues are ballooning with projects seeking interconnection as the generation cost of renewables drops below natural gas. The cost to interconnect clean energy projects rises as congestion on the grid increases. As a result, clean energy projects are already dropping out of the interconnection queue at an increasing rate. Transmission delays and rising costs have a disparate impact on clean energy projects, since they represent the majority of new generation projects getting built. A 2020 analysis of the MISO queue examines the rising cost of interconnection, showing interconnection costs rising to $1000/kW, which in some cases is almost equivalent to the cost to build the generation project itself. It is not economically viable to double the cost of a clean generation facility by constraining the solution set for transmission upgrades to wires-only solutions.

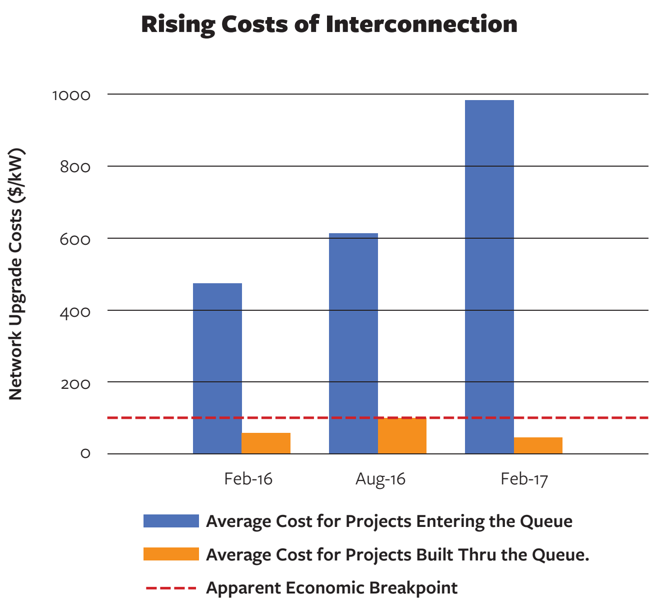
Transmission lines can also be much more expensive than GETs alternatives. The major electric utilities in the United States spend over $20 billion per year on transmission infrastructure, even though as much as 85% of our existing transmission infrastructure is operating at less than 50% of its capacity under normal operating conditions. Similar to generation, the transmission system is built to accommodate the one peak load hour per year. Targeted solutions to surgically mitigate peaks can be much cheaper than building whole new transmission lines.

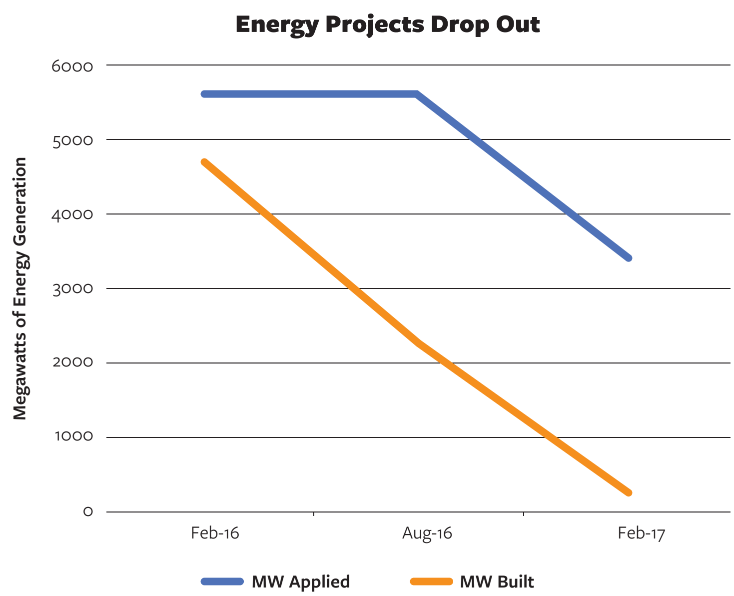
Experts have estimated that the cost of additional transmission necessary to reach 100% renewables in the United States could be as much as $700 billion, a prohibitive cost that doesn't even take into account the significant environmental and land-use impacts that would accompany such a massive transmission build-out. While this expense benefits the current incumbent transmission owners, who are awarded a guaranteed rate of return on these large projects, reliance solely on wires solutions dramatically increases the cost and time of adding the renewables we need to meet society's carbon goals.

Advanced transmission technologies can significantly reduce the cost of renewables integration as compared to wires strategies alone. A 2021 analysis prepared for the WATT Coalition determined the addition of power flow technology, dynamic line rating, and topology optimization

Interconnection Costs Prevent Energy Projects from Completion

Generation interconnection for MISO-WEST (includes parts of MN, IA, WI, IL)





Source: Midcontinent Independent System Operator (MISO) could more than double the amount of wind generation that can be interconnected in the Southwest Power Pool (SPP), from 2.5 GW to 5.2 GW, at a cost of only $90M. (To put the cost in context, MISO 2020 Transmission Expansion Plan proposes $4.2B in wires-based transmission line upgrades.) Similarly, a 2016 analysis of the cost to upgrade PJM's grid to 30% renewables concluded that adding power flow controls to transmission would save ratepayers approximately $1.8 billion as compared to a wires-only approach ($2.2B vs. $4B). Adding energy storage, local solar, and other DERs operating as advanced transmission technologies could likely reduce this cost even further.

Transmission Planners and Utilities Undervalue Advanced Transmission Technologies in the Planning Process

While energy storage and other advanced transmission technologies could provide a faster "on-ramp" for renewable energy projects stranded in ISO interconnection queues, the current transmission planning process thwarts reasonable consideration of these alternatives. As noted by former FERC Chairman Jon Wellinghoff, grid-enhancing technologies "can do for the transmission system what smart meters did at the distribution level ... but they aren't being deployed because transmission developers have no incentive to use them." In order to incorporate and fairly value these advanced technologies in long-term planning, here are four ways that the transmission planning, modeling, and operations must improve.

First, planners should require transmission owners to report the utilization rates of existing transmission lines. In most infrastructure-dependent industries, we consider utilization of fixed cost capital assets a measure of efficiency, but we hold no such standards for monopoly transmission owners. They are not even required to determine the efficiency of the transmission system, despite the billions they cost us. It is important to get a better handle on utilization rates across the country, while also recognizing the need for redundancy and backup in cases of a fault on a transmission line.

Second, FERC must level the playing field for non-wires transmission solutions. The current transmission planning process in the United States provides an undue advantage for wires-only transmission projects over nimbler, cost-effective, technologically advanced alternative solutions. Skewing planning towards a specific (wires-based) transmission technology is unjust and unreasonable, and it threatens to block the timely achievement of our nation's clean energy transition. Wires-only projects are becoming increasingly difficult to permit and build because of the public's concerns about the impact of transmission lines on landscapes, habitats, and communities, as well as increasing costs. FERC and the RTOs must reform the planning process to ensure full consideration of technologies that can help integrate renewables better, cheaper, and faster. Recent work at FERC has been a great step forward, but we need to ensure that any ISO/RTO tariff changes in this area provide a level playing field for all technologies.

Third, FERC must ensure comparable cost allocation for advanced transmission technologies. Transmission planners too often shunt advanced transmission technologies into categories such as "non-transmission alternatives" where they are either not compensated or left to fend for themselves in the wholesale markets while traditional wires solutions receive regional cost allocation for providing the same transmission services. This is a clear violation of the Federal Power Act's focus on technology-neutral services and prohibition of unduly discriminatory rates. Even when they are eligible for return on equity cost allocation, grid- enhancing technologies are often less expensive than traditional wires projects and so are less valuable to the incumbent utility, in that they generate a lower total profit for utility shareholders. New cost allocation and shared incentives rules and requirements would make grid-enhancing technologies attractive to both incumbent utilities and new entrants alike. We need to broaden the types of projects that can be compensated as transmission and incorporate appropriate incentives to level the playing field.

Finally, FERC and the RTOs must reform the generator interconnection process. Interconnection improvements could reduce the time and expense of connecting new wind and solar projects to the grid. RTO interconnection studies increasingly subject renewables projects to huge transmission upgrade costs based in large part on the purported need to construct high-voltage transmission lines to accommodate the new generation. FERC should require RTOs to begin properly considering how energy storage and other advanced technologies could reduce those upgrade costs and delays.

FERC will play an important role in fixing the flaws in the existing transmission planning and compensation regime. Thanks in large part to the WATT Coalition, Jon Wellinghoff, and others, FERC has recently begun to recognize the value that grid-enhancing technologies can provide. In 2020, FERC proposed two rulemakings - RM20-10 and RM20-16 - that begin to address grid- enhancing technologies through transmission incentives and requirements to standardize transmission line ratings. The tide is turning, and momentum is slowly building to move beyond wires and include a broader range of transmission technologies to accelerate the United States' transition to renewable energy.

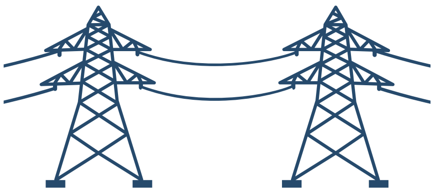
Momentum is Growing

Momentum is building to rethink transmission and technologies that can participate

- **2010**
  - Western Grid Declaratory Order
- **2011**
  - FERC Order 1000
- **2017**
  - FERC policy statement allowing cost recovery for storage
- **2018**
  - First Storage Projects Submitted to PJM RTEP
  - CAISO Selects OCEI
  - FERC Order 841
- **2019**
  - FERC Order on Transmission Incentives
- **2020**
  - MISO SATOA Petition & FERC Order
  - GETS Technical Conference
  - FERC rulemaking on dynamic line rating
  - FERC Order 2222
  - FERC conference on transmission incentives

Plan of Action

The Beyond Wires Coalition works to ensure that transmission and distribution-connected technologies are fully considered and optimally deployed to maximize the cost-effective delivery of renewable electricity while maintaining reliability. ELPC is working with the Center for Renewables Integration (CRI) on this project, with feedback from other organizations, thought leaders, and businesses. This work will require significant advocacy and participation at the federal, regional, and state levels, starting with these three areas of policy and legal intervention:



1. Utilization

We will advocate for increased transparency and the development of utilization metrics to show how electricity is used throughout the grid on a more granular level. Regular and standardized transmission utilization studies will help identify opportunities for targeted non-wires solutions.

2. Planning

We must ensure distribution-connected resources and other grid enhancing technologies are given full consideration in the energy planning process. Utilities must be required to present, and RTOs to evaluate, whether these technologies could replace or reduce the cost of traditional large wires solutions to grid and interconnection needs.

3. Compensation

Our current transmission planning process gives undue advantage to wires-only solutions. We will push for rule/tariff changes to fairly compensate grid- enhancing technology and distribution-connected resources when they are providing transmission services. This will create a level playing field for all possible transmission solutions.

At the federal level, we are exploring opportunities to initiate new actions at FERC challenging the status quo of comparable treatment and cost allocation for advanced transmission technologies through rule and tariff changes. To the extent that FERC or Congress acts, there will be considerable work to be done to ensure that regional grid operators effectively and fairly implement any new federal policies. The Beyond Wires Coalition is already working to expand consideration of advanced transmission technologies in multiple states and RTOs, including CAISO, MISO, and PJM. We expect all three of those grid operators to make major steps toward advanced transmission technologies in the next year.

Our planned work on advanced transmission technologies will dovetail with ELPC and our regional partners' existing work to integrate storage and other technologies in Midwest states. The success of this project will depend on effective partnerships with other leading advocacy and industry groups. We intend to engage other leading organizations as potential partners in this work. These organizations and companies will help us adjust and flesh out this plan moving forward.

Conclusion

As battery storage, distributed solar photovoltaics, and other resources become increasingly affordable, these technologies are unlocking new opportunities to meet transmission needs and accelerate renewable energy deployment. It is time for the Midwest, and the United States as a whole, to take full advantage of advanced transmission technologies to modernize electricity delivery and meet our society's urgent climate goals.

A massive societal shift towards renewable energy is needed to meet the global climate crisis. Communities, manufacturers, and Americans of all stripes are eager to build out the clean energy generation that will get us there. We cannot afford to let our outdated transmission system and dysfunctional planning process hold us back. Energy storage and other novel transmission technologies must be part of the solution. Thinking beyond wires can help to reduce carbon pollution, protect the environment, limit costs, increase flexibility, create jobs, and promote transparency and competition. The Beyond Wires Coalition will work to accelerate smart technology to meet the energy challenges of the 21 st century.

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ENVIRONMENTAL LAW & POLICY CENTER

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Interconnection Cost Analysis in the Midcontinent Independent System Operator (MISO) Territory

Interconnection costs have escalated as interconnection requests have grown

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Executive summary

Interconnection queues have grown dramatically throughout the United States. In MISO, the cumulative capacity of projects actively seeking interconnection more than doubled from 2016 through 2021. Based on available data on project-level interconnection costs from MISO, our analysis finds:

- **Average interconnection costs have grown**. Project-specific costs can differ widely depending on many variables. We focus on average costs as a key cost metric. For projects that have completed all required interconnection studies (dubbed "complete" request status), average costs have nearly doubled (to $102/kW) for more recent projects relative to costs from 2000-2018 ($58/kW). Projects still actively moving through the queue ("active") have estimated costs that have more than tripled just over the last four years, from $48/kW to $156/kW (2018 vs. 2019-2021).
- **Projects that have completed all required interconnection studies have the lowest costs.** Costs averaged $102/kW for complete projects from 2019 through 2021. Projects that are actively progressing through the study process but have not yet completed all studies have higher costs ($156/kW), while the interconnection requests that ultimately withdraw from the queue ("withdrawn") face the highest costs ($452/kW)—likely a key driver for those withdrawals.
- **Broader network upgrade costs are the primary driver of recent cost increases.** Costs for local facilities at the point of interconnection are similar for complete ($46/kW) and active ($48/kW), but larger for withdrawn projects ($67/kW). Costs for broader network upgrades beyond the interconnecting substation explain most cost differences and have risen sharply. Estimated network upgrade costs have grown since 2018, to $57/kW for complete projects and $107/kW for active projects. Among withdrawn projects, they make up 85% of the costs at $388/kW for recent projects.
- **Potential interconnection costs of wind ($399/kW), storage ($248/kW), and solar ($209/kW) have been greater than natural gas ($108/kW) projects in recent years** (2018-2021). Wind projects bear the greatest costs compared to other resource types: Wind projects that completed the interconnection study process in 2021 faced a record average of $252/kW, nearly four times the historical average and about 16% of typical total wind installation costs in MISO. Wind projects that ultimately withdrew had average interconnection costs of $631/kW (equivalent to 40% of total project installed costs), compared with $358/kW (or 24% of installation costs) for withdrawn solar applicants.
- **Larger generators have greater interconnection costs in absolute terms, but economies of scale exist on a per kW basis.** Medium-sized wind ($491/kW) and solar ($259/kW) projects face twice the potential interconnection costs per unit of capacity compared to very large wind ($222/kW) and solar ($125/kW) projects.
- **Interconnection costs also vary by location**, with projects in the eastern part of MISO (Indiana and Illinois) reporting overall lower costs, irrespective of request status ($50-70/kW). Applicants in the north (North and South Dakota) and parts of Texas have high potential interconnection costs (average of $508-915/kW).

The cost sample analyzed here represents nearly 50% of all projects requesting interconnection from 2010 to 2020, or 30% when going further back in time to the year 2000. While it is sufficiently robust for detailed analysis, much data remains unavailable to the public. The paucity of easily accessible interconnection cost data poses an information barrier for prospective developers, resulting in a less efficient interconnection process. We have posted project-level cost data from this analysis at https://emp.lbl.gov/interconnection_costs.

1. The interconnection queue doubled in capacity over the past few years

As of the end of 2021, the Midcontinent Independent System Operator (MISO) had over 160 gigawatts (GW) of generation and storage capacity actively seeking grid interconnection. This "active" capacity in MISO's queue is dominated by solar (112 GW) and, to a lesser extent, wind (22 GW) power capacity. MISO's queue also contains additional data for projects that are no longer actively seeking interconnection: 366 GW of projects have withdrawn their application and 62 GW of projects are already in service (Rand et al. 2022). Submissions for MISO's 2022 Generator Interconnection Queue again broke all records, increasing by 220% over 2021 levels. If all submissions are accepted as valid, the active MISO queue would balloon to 289 GW, more than 95% of which are either renewable power or energy storage (MISO 2022). The capacity associated with these requests is more than twice as large as MISO's peak load in recent years (about 120 GW) and, if substantial amounts are built, will likely exert competitive pressure on existing generation. However, most projects have historically withdrawn their applications: only 24% of all projects requesting interconnection between 2000 and 2016 have ultimately achieved commercial operation at the end of 2021.

MISO has implemented numerous interconnection process reforms since 2008 to reduce queue delays and project cancellations. These reforms, for example, shifted MISO's procedures for processing interconnection requests away from a "first-come, first-served" serial approach to a "first-ready, first-served" cluster study approach with annual cluster windows in each of the five MISO regions. In 2016, MISO introduced new "at risk" payments to enhance project readiness at interim milestones and, starting with the 2020 queue cycle, MISO established more stringent site control requirements for projects to progress through the queue (Bergan et al. 2012; Caspary et al. 2021). MISO has also increased efforts to expand the transmission network. The ISO recently approved $10 billion of new bulk transmission, while their Joint Targeted Interconnection Queue initiative aims to invest $1 billion to address transmission needs along the MISO-SPP seam.

2. Cost sample represents nearly 50% of projects requesting interconnection over the past decade

This brief analyzes interconnection cost data from 922 projects that were evaluated in interconnection studies between 2001 and 2021, equivalent to 28% of all projects requesting interconnection to the MISO system during that time (see left panel in Figure 1); the cost sample increases to 48% of projects when focusing on a more recent time period of 2011 through 2020.

Our interconnection cost sample has two sources:

- All data that were available in the MISO system as of February 2022: 698 projects (MISO 2022).
- Data for 224 additional projects that were already collected in 2018 and that had since been removed from the online MISO system (Gorman, Mills, and Wiser 2019).

While the sample is sufficiently robust to enable detailed analysis of interconnection costs, it represents a subset of all projects. MISO removes detailed interconnection study information after a few years from their publicly accessible records, explaining the paucity of data for earlier years. We were also not able to analyze costs for projects entering the queue in 2021 and beyond as interconnection studies with cost estimates are performed and published with some delay. The lack of easily accessible interconnection cost data poses an information barrier for prospective developers, resulting in a less efficient interconnection process. We have posted project-level cost data from this analysis at https://emp.lbl.gov/interconnection_costs.

Interconnection Request Status Definitions

Complete: These projects have completed all of the interconnection studies, and have moved on to (or completed) the interconnection agreement phase. This includes plants that are now in service.

Active: These projects are actively working through the interconnection study process.

Withdrawn: These interconnection requests have been withdrawn (cancelled) from the queue.

The sample varies over time with respect to request status (see right panel in Figure 1). Data for completed projects goes back furthest in time and makes up the largest portion of our cost sample (370 projects, 56.9 GW). Some projects ultimately withdraw from the interconnection process for a variety of reasons; our data includes 314 such projects (48.1 GW) that were studied between 2018 and 2021. Projects that are still active in the interconnection study process were primarily evaluated in 2021 (total of 238 projects, 37.8 GW).

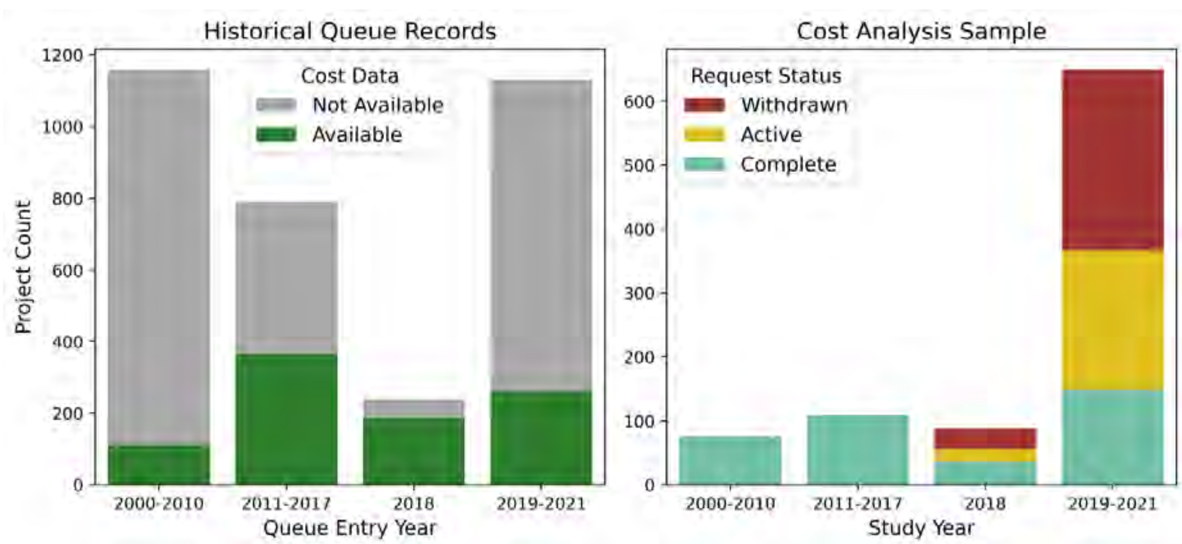

Figure 1 Sample: Availability of Cost Data Relative to Historical Queue Records *(left)*, **and Cost Data by Request Status** *(right). The left graph shows all historical projects seeking interconnection, indexed by their queue entry year. The right graph represents our cost analysis sample, with projects indexed by the year of the last available interconnection study. The remainder of this briefing will index projects by their study year.*

3. Interconnection costs have grown, driven by network upgrade expenses

Interconnection cost data were collected manually from public interconnection study reports, using the most recent study type available (feasibility studies, system impact studies, and addendums). The interconnection cost data summarized here are based exclusively on cost estimates in interconnection study reports and do not include potential additional interconnection-related expenses that may be borne by a project developer. We assume the reported costs refer to nominal dollars as of the time of the interconnection study and present costs in real \$2022-terms based on a GDP deflator conversion. We present interconnection costs in \$/kW to facilitate comparisons, using the nameplate capacity of each project. We report simple means with standard errors throughout the briefing as detailed in the textbox on the next page.

Interconnection Cost Metrics

The cost data do not have the shape of a normal distribution: many projects have rather low costs (or cost components), while a few projects have very high costs. We give summary statistics throughout the core briefing as **simple means** to judge macro-level trends. Below is an illustrative example using completed project costs between 2018 and 2021. The histogram shows that more than 90% of all projects in this sample have interconnection costs under $200/kW, but a few cluster around $400/kW and one project has costs of $1,241/kW (Figure 2, left). Medians (dashed-line in the center of the boxplot) describe a "typical" project, with costs of $60/kW, but individual cost components cannot be added to meaningful sums. Means (Figure 2, right) are susceptible to the influence of a small number of projects with very high costs, and are often a bit higher than medians ($97/kW), but aggregated cost-components can easily be added. We include the standard error of the mean ($\hat{\sigma}_{\bar{x}}$) as a measure of dispersion to give a sense of how scattered the data are. We point to median values in footnotes throughout the text.

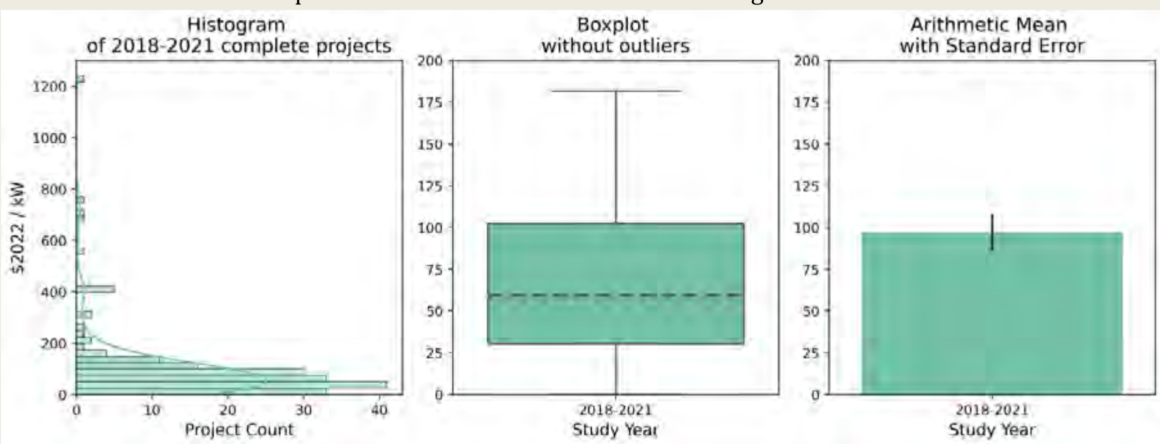

Figure 2 Interconnection Cost Metrics Example: Subsample of Projects that Complete Study Process, 2018-2021

The appendix contains more information about the distribution of the cost data, showing box-plot versions of all graphs and illustrating the very wide spread in the underlying data from which the averages are derived in the core briefing.

3.1 Average interconnection costs have grown over time

Potential interconnection costs across all applicants increase in our sample after 2000. However, combining all projects – regardless of request status – is problematic. Our cost sample composition changes over time, primarily containing completed projects in the early years, but with growing numbers of active and withdrawn projects in the later years (see Figure 1). Focusing on any given study cohort, one would expect that average interconnection costs would decline as projects proceed through the queue and high cost projects naturally withdraw.

But the trend of increasing interconnection costs also holds true when accounting for the request status of a project applicant (see Figure 3). Among the projects with completed interconnection studies, interconnection costs nearly double from $58/kW prior to 2019 to $102/kW between 2019 and 2021 (the standard error of the mean $\hat{\sigma}_{\bar{x}}$ $11/kW and $12/kW respectively). Projects that were still actively moving through the interconnection queues see more than a cost tripling, from $48/kW to $156/kW (2018 vs. 2019-

2021, $\hat{\sigma}_{\bar{x}}$=11&13). Projects that ultimately withdraw have stable costs at $453/kW and $452/kW (2018 vs. 2019-2021, $\hat{\sigma}_{\bar{x}}$=69&36).[1] Although average costs for withdrawn projects have remained stable, they are more than four times the costs of "complete" projects over the past four years ($453/kW vs. $147/kW, $\hat{\sigma}_{\bar{x}}$=33&12).[2]

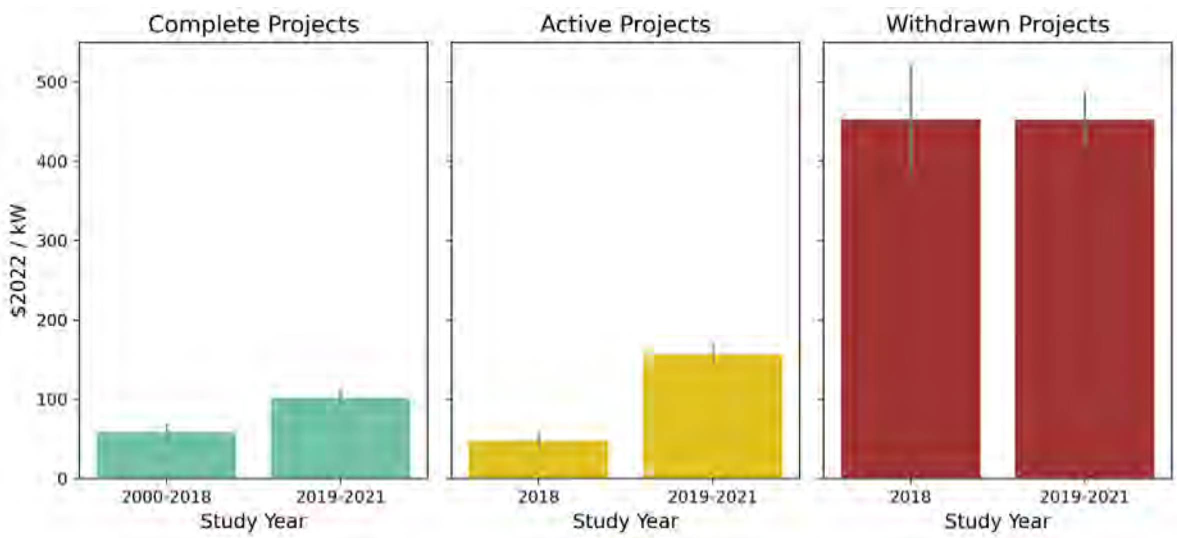

Figure 3 Interconnection Costs over Time by Request Status *(bars show simple means, gray lines represent standard error)*

3.2 Broader network upgrade costs are the primary driver of recent cost increases

We group costs identified in the interconnection studies into two large categories shown in Figure 4:
(1) Local interconnection facility costs describing investments at the point of interconnection (POI) with the broader transmission system, and (2) broader network upgrade costs.[3]

Among the projects that successfully complete all interconnection studies, local upgrades at the POI have historically been a significant cost driver, accounting for $46/kW (2018-2021, $\hat{\sigma}_{\bar{x}}$=3). A rise in these POI costs is also the primary reason for interconnection cost escalations since the early 2000s in this subsample. Yet, network upgrade costs can cause large cost additions for some projects and seem to be growing in recent years (from $31/kW in 2018 to $57/kW from 2019 to 2021, $\hat{\sigma}_{\bar{x}}$=17&12, Figure 4).[4]

Projects that are still being actively evaluated have similar POI costs, growing from $31/kW to $50/kW in the past four years ($\hat{\sigma}_{\bar{x}}$=7&4, Figure 4). However, network costs are the real cost driver: they are greater

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[1] Median costs grow fivefold for completed projects ($12 to $65/kW) and double for active projects ($46 to $95/kW). The trend among withdrawn is less clear when looking at medians: costs fall from $472/kW in 2018 to $171/kW in 2020 and rise again to $322/kW in 2021.
[2] Median costs for withdrawn projects are also four times the costs of complete projects over the period 2018-2021 ($265 vs. $60/kW).
[3] POI costs usually do not include electrical facilities at the generator itself like transformers or spur lines. Instead they are predominantly driven by the construction of an interconnection station and transmission line extensions to those interconnection stations. The categories are referred to as "Interconnection Facilities" in the interconnection studies and include Transmission Owner Network Upgrade and Transmission Owner-Owned Direct Assigned (or TOIF) expenses.
Network costs refer to upgrades classified as Backbone Network Upgrades, Thermal/Voltage/Steady State/Reactive/Transient Stability, Short Circuit, Local Planning Criteria, Affected System, Deliverability, and Shared Network Upgrade.
[4] For complete projects in 2018-2021, median POI costs are $35/kW, median network costs are $0/kW (see also Figure 10 in the Appendix).

compared to completed projects, again featuring at times projects with very high costs, and rising over the past four years from $16/kW to $107/kW ($\hat{\sigma}_{\bar{x}}$=10&13, Figure 4).[5]

The situation is very different for projects that ultimately withdraw from the interconnection process. While POI costs are typically a bit higher at $67/kW ($\hat{\sigma}_{\bar{x}}$=4, 2018-2021), the required network upgrades are commonly much larger and have grown in recent years from $366/kW to $388/kW ($\hat{\sigma}_{\bar{x}}$=65&36, Figure 4). The top 10% of network upgrade costs range between $900/kW and $4600/kW.[6] High network upgrade costs are often related to a lack of transmission in the geographic region of the applicant or high levels of congestion.

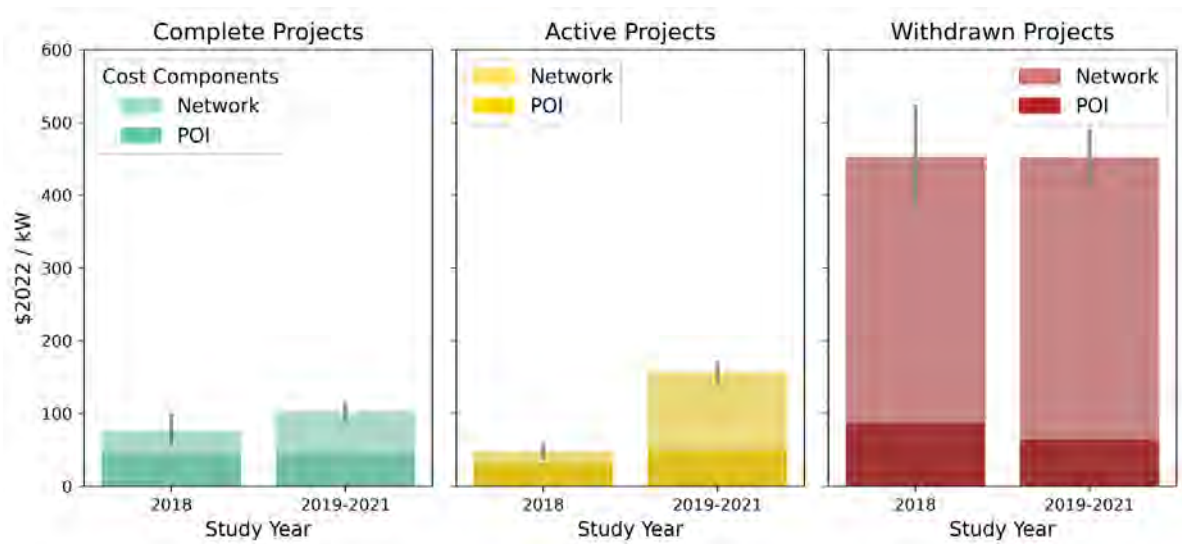

Figure 4 Interconnection Costs by Cost Category and Request Status *(bars: means, gray lines: standard error of total costs)*

Affected System Costs

Stakeholders have sometimes expressed particular concern about 'affected system' studies, which can result in assessed interconnection costs outside of the region to which the generator is interconnecting—an adjacent ISO, for example, and sometimes at great distance from the generator's proposed location. In part as a result, MISO and SPP have proposed reforming the affected system study process; so too has FERC, in its interconnection NOPR.

Between 2018 and 2021, regardless of request status, 27% of projects (196 in total) have listed estimates for 'affected system' interconnection costs. Among that subset, the average 'affected system' interconnection cost is $121/kW, representing usually half of the recorded network costs and on average 26% of their total interconnection costs; Costs are greater for wind ($186/kW) and solar ($62/kW) than natural gas ($18/kW). Projects that ultimately withdraw have higher affected system costs ($186/kW) than projects that complete all studies ($70/kW) or that are still actively seeking interconnection ($34/kW). Among projects that completed all interconnection studies, affected system costs have recently nearly quadrupled to $77/kW (2019-2021) compared with $21/kW in earlier years (2015-2018).

[5] For active projects in 2018-2021, median POI costs are $35/kW, median network costs are $30/kW (see also Figure 10 in the Appendix).
[6] For withdrawn projects in 2018-2021, median POI costs are $51/kW, median network costs are $160/kW (see Figure 10 in the Appendix).

3.3 Interconnection costs for wind, storage, and solar are larger than for natural gas

Interconnection costs vary by the fuel type of the generator seeking interconnection, both in terms of the magnitude and composition of cost drivers. The cost sample contains primarily solar (409), wind (313), natural gas (79), and storage (57) projects, but in earlier years also some coal (20) and hydro (14) plants. Wind ($399/kW), storage ($248/kW), and solar ($209/kW) costs are greater than natural gas ($108/kW) costs when looking at all recent projects, irrespective of their request status (see left panel in Figure 5).[7]

The sample offers the longest time record for projects that complete interconnection studies. Looking at projects studied before and after 2019, we find that natural gas interconnection costs fall from $59/kW to $44/kW ($\hat{\sigma}_{\bar{x}}$=22&15). Cost escalations are evident, on the other hand, for renewables: average solar costs grow from $62/kW to $88/kW ($\hat{\sigma}_{\bar{x}}$=10), whereas wind costs double from $73/kW to $141/kW ($\hat{\sigma}_{\bar{x}}$=22&30, see right panel in Figure 5). Interconnection costs for wind escalated further when looking only at the year 2021, reaching $252/kW ($\hat{\sigma}_{\bar{x}}$=87) or nearly four times the historical average. Interconnection costs of this magnitude represent about 16% of total wind project installation costs in MISO (Wiser et al. 2022).[8] Interconnection costs of completed solar projects in 2021 are a smaller fraction of overall project costs, accounting for $99/kW ($\hat{\sigma}_{\bar{x}}$=23) or 7% of overall solar project installation costs in MISO in 2021 (Bolinger et al. 2022). One potential driver of the larger interconnection costs for wind and solar may be siting differences, as renewable generators are typically located in more rural areas with fewer nearby substations.

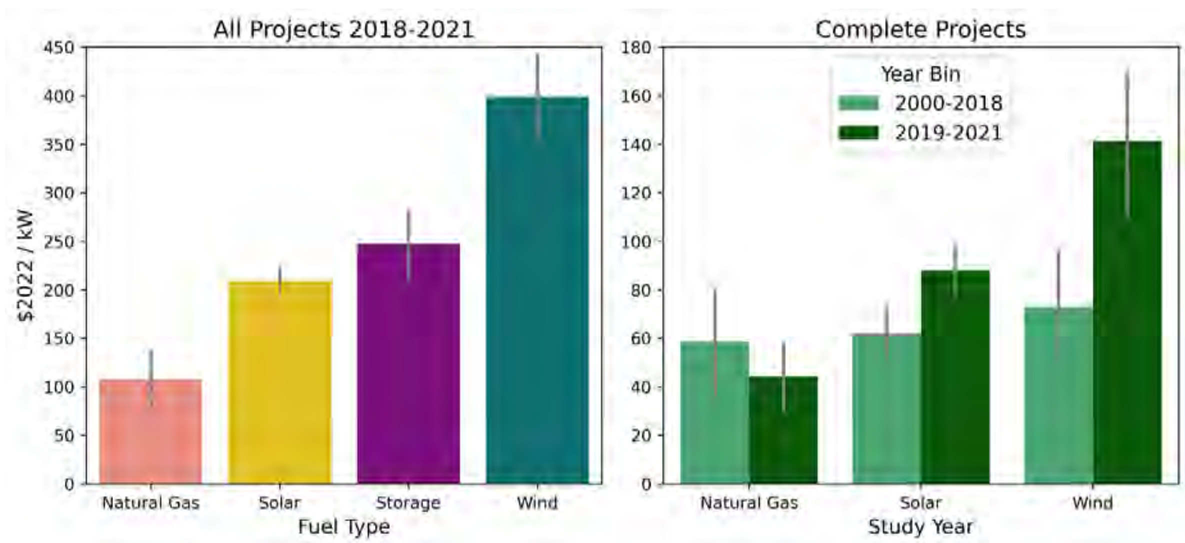

Figure 5 Interconnection Costs by Fuel Type (left) and Over Time for Complete Projects (right) *(bars: means, gray lines: standard error)*

The breakdown of interconnection costs into POI and network costs also differs by fuel type. Figure 6 investigates the distribution of interconnection costs across all projects in our 2018-2021 sample. POI costs

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[7] $\hat{\sigma}_{\bar{x}}$ = 44, 35, 14, and 29. The same trend is evident if we examine median interconnection costs for storage ($148/kW), wind ($107/kW), and solar ($104/kW) vs. natural gas ($31/kW), see Figure 12 in the Appendix. We only have one recent coal project, coming in at $29/kW.
[8] Median natural gas interconnection costs used to be negligible at $4/kW but rise to $43/kW, solar cost grow slightly from $59/kW to $65/kW, and wind costs double from $36/kW to $74/kW

do not vary much, except for rather low costs for natural gas and unusually high POI costs for some storage projects. The high storage costs may be driven by storage dispatch assumptions used in the interconnection studies that presumed storage to charge during high load hours.

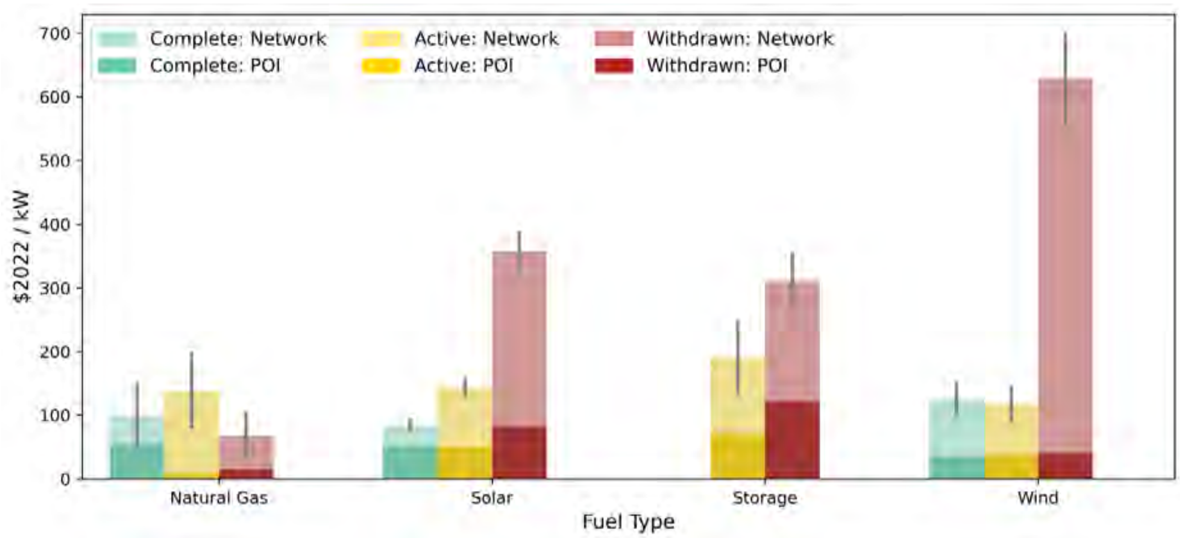

Figure 6 Interconnection Costs by Fuel Type, Cost Category, Request Status *(bars: means, gray lines: standard error of total costs, 2018-2021)*

In contrast, network costs increase dramatically for active and withdrawn projects. Network costs are three times greater than POI costs for withdrawn solar projects ($275/kW vs. $82/kW) and fifteen times greater for withdrawn wind projects ($590/kW vs $40/kW).[9] High total interconnection costs of $631/kW ($\hat{\sigma}_{\bar{x}}$=73, or 40% of overall wind project installation costs (Wiser et al. 2022)) could explain why wind projects withdraw from the queue. Total interconnection costs of withdrawing solar projects are lower at $358/kW ($\hat{\sigma}_{\bar{x}}$=30), but would still account for 24% of installed project costs (Bolinger et al. 2022).

3.4 Larger generators have greater interconnection costs in absolute terms, but economies of scale exist on a per kW basis

Projects with larger nameplate capacity ratings have greater interconnection costs in absolute terms, on average and irrespective of whether projects ultimately come online or withdraw. Between 2018 and 2021, projects smaller than 20 MW have average costs of $7 Million, which compares to $16 Million for medium-sized projects between 20 and 100 MW, $40 Million for large (100-250 MW), and $65 Million for very large (250-1500 MW) projects.

But these costs do not scale linearly on a per kW basis. Costs fall from $705/kW for small projects to $283/kW, $259/kW, and $167/kW for medium, large, and very large project sizes, respectively, suggesting substantial economies of scale.[10] The size efficiencies generally hold both for POI and network costs—very large projects thus do not seem to bear atypically high interconnection costs or trigger unusually costly

[9] $\hat{\sigma}_{\bar{x}}$ for withdrawn solar are 29 & 6, for wind 72 & 3. Median network costs are two times greater than POI costs for withdrawn solar projects (median: $123 vs $65/kW) and ten times greater for wind projects ($347 vs $35/kW).
[10] $\hat{\sigma}_{\bar{x}}$ across size bins are 311, 32, 18, and 26.

network upgrades. In fact, the larger initial investment may enable developers to preselect better sites that result in lower interconnection costs relative to project size.

Economies of scale also persist across the three different requests statuses (see Figure 7). Very small projects that complete the study process seem to have atypically low costs ($9/kW), but this subsample is small (6 observations) and therefore may be skewed – small active and especially small withdrawn projects have much higher costs, driven by very large network upgrade costs relative to their size.

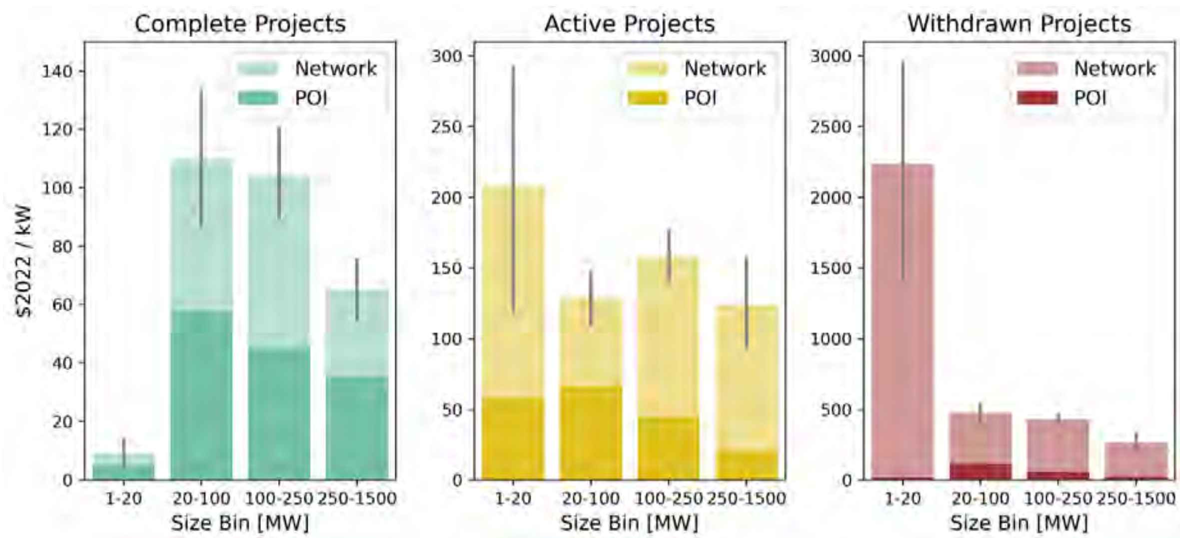

Figure 7 Interconnection Costs by Capacity and Request Status *(bars: means, gray lines: standard error of total costs, 2018-2021, y-axes differ by panel)*

Economies of scale largely hold when accounting for fuel type: Medium solar projects (20-100 MW) have greater costs ($259/kW) compared to large (100-250 MW: $200/kW) or very large projects (250-1500 MW: $125/kW), and the same is true for wind projects (20-100 MW: $491/kW, 100-250 MW: $373/kW, 250-1500 MW: $222/kW).[11] Costs for natural gas and storage, on the other hand, do not vary significantly by size (see Appendix, Figure 13).

We can only compare longer time trends for the subsample that has completed the interconnection studies, but find that larger projects have consistently lower costs compared with their smaller counterparts since 2010, and a per-kW basis.

3.5 Interconnection costs vary by location

Interconnection costs also vary by location, with eastern projects in Illinois ($50/kW) and Indiana ($69/kW) reporting overall lower costs across all projects studied between 2018 and 2021 (irrespective of whether they ultimately complete the interconnection process). Applicants in North and South Dakota and parts of Texas, on the other hand, have high average interconnection costs ($508-915/kW). Overall there is some alignment between states with high interconnection costs and those with little available transmission capacity, which are located primarily in in the north of the ISO (MISO, 2022).

[11] $\hat{\sigma}_{\bar{x}}$ for solar across size bins are 38, 14, 28; $\hat{\sigma}_{\bar{x}}$ for wind are 142, 45, 48.

Figure 8 examines cost variation by state and project status request: Northern states have again comparatively high interconnection costs among complete (Minnesota: $159/kW) and withdrawn (North Dakota: $1001/kW) projects, while eastern projects in Illinois and Indiana are assigned lower costs ($42/kW and $43/kW for completed; $28/kW and $60/kW for withdrawn projects). Southern states such as parts of Texas ($416/kW) and Louisiana ($306/kW) have the greatest interconnection costs among projects that are still actively being assessed.

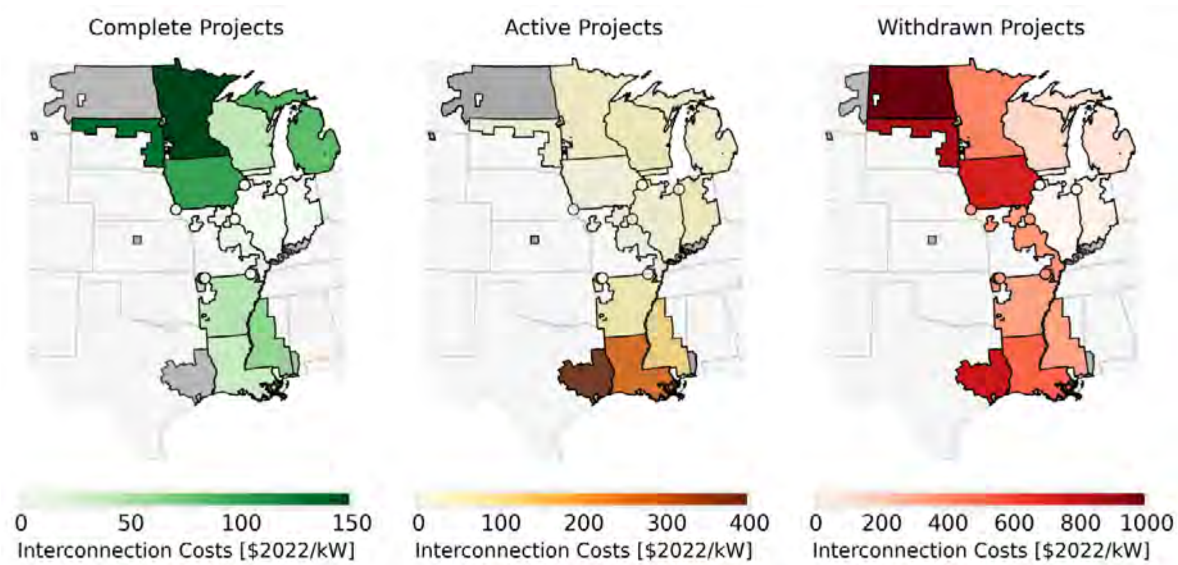

Figure 8 Interconnection Costs by State and Request Status *(means, 2018-2021, grey areas indicate insufficient data)*

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Acknowledgements

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For other interconnection related work, see https://emp.lbl.gov/interconnection_costs and https://emp.lbl.gov/queues
For the DOE i2X program, see https://www.energy.gov/eere/i2x/interconnection-innovation-e-xchange
For all of our downloadable publications, visit https://emp.lbl.gov/publications
To contact the corresponding author, email jseel@lbl.gov

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4. Appendix

This appendix includes boxplot versions of the graphs in the core report, highlighting the broad distribution of interconnection costs that underlie the previously presented means. The boxplot median is highlighted with a bolder dashed line, the lower and upper box line represent the 25th and 75th percentile. The lower/upper whiskers are 1.5x of the interquartile range below/above the 25th and 75th percentile. Not all outliers are shown to keep the graphs legible. Y-axes may differ by panel.

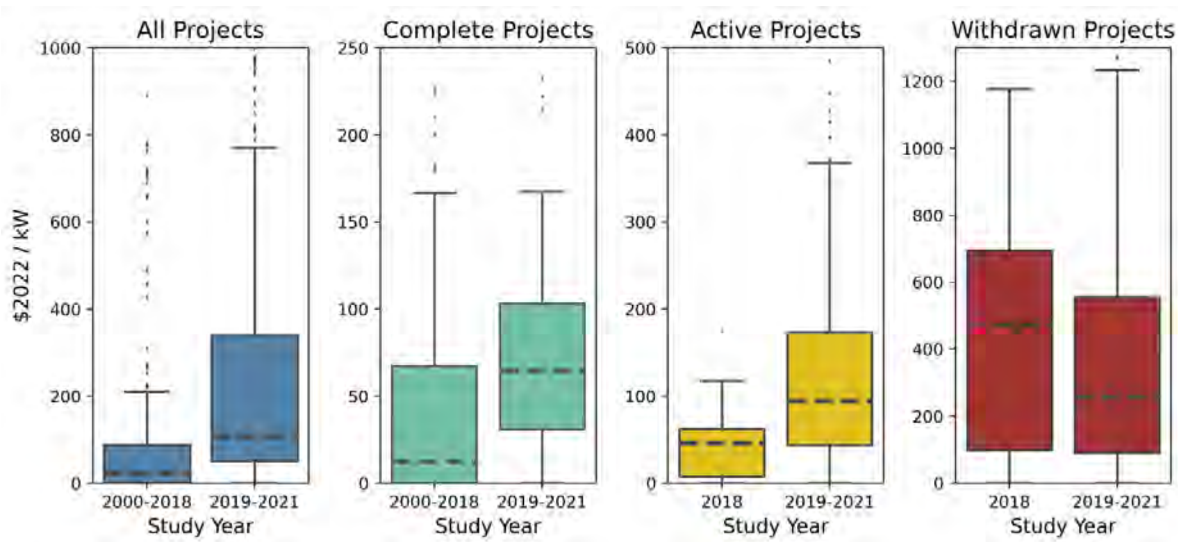

Figure 9 Interconnection Costs over Time by Request Status *(y-axes differ by panel, not all outliers outside 1.5x interquartile range are shown)*

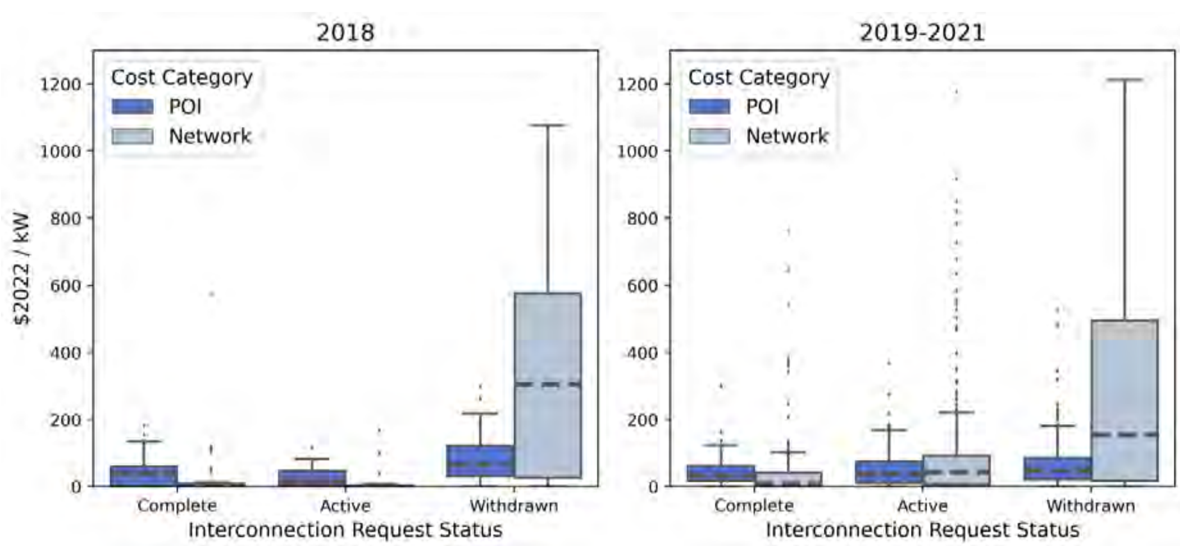

Figure 10 Interconnection Costs by Request Status and Cost Category *(not all outliers outside 1.5x interquartile range are shown)*

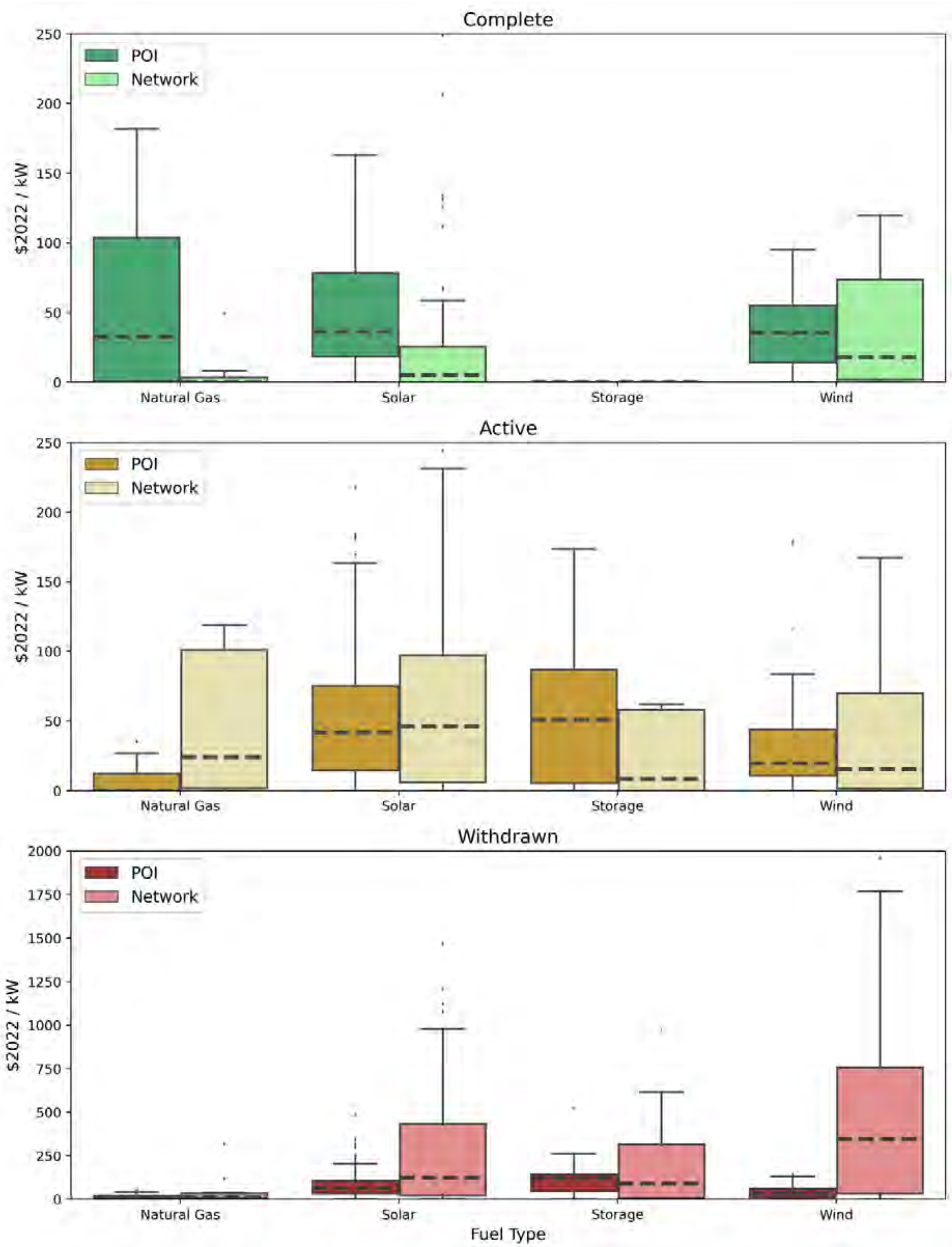

Figure 11 Interconnection Costs by Fuel Type, Request Status, and Cost Category *(2018-2021, not all outliers are shown)*

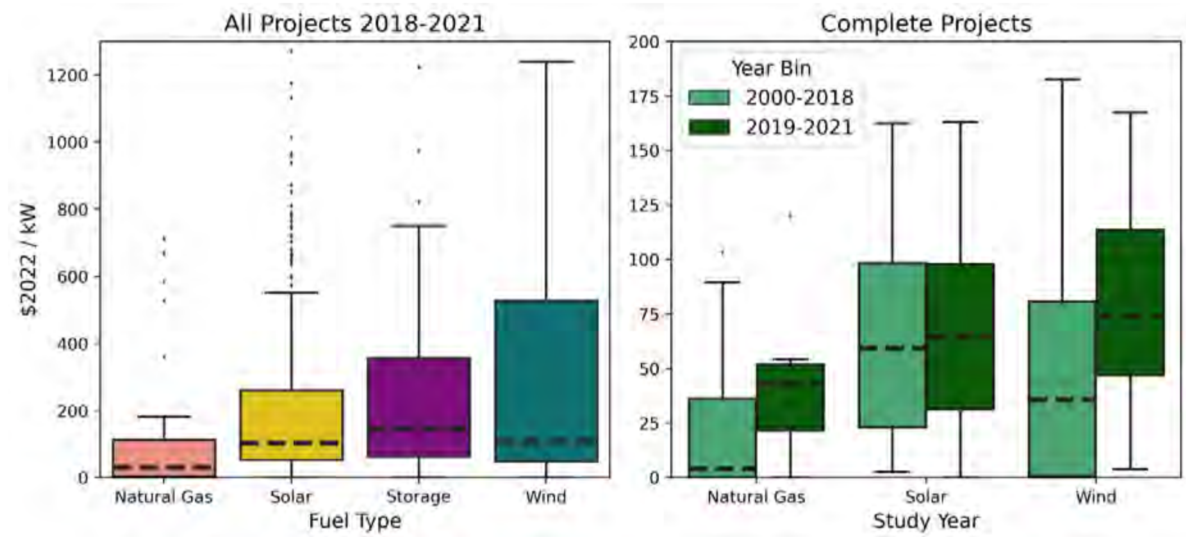

Figure 12 Interconnection Costs by Fuel Type (left) and Over Time for Complete Projects (right) *(not all outliers are shown)*

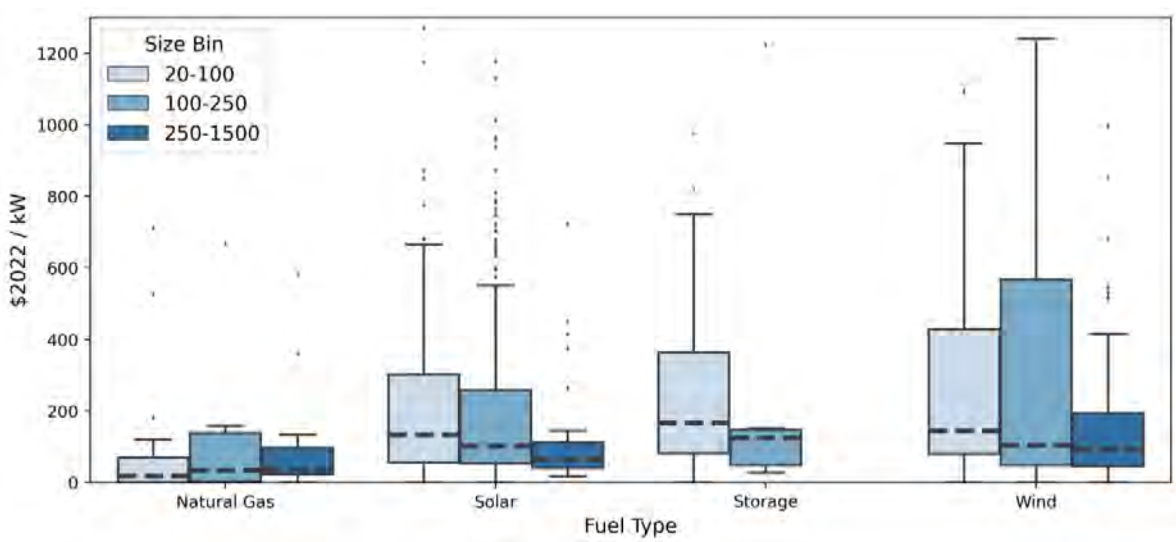

Figure 13 Interconnection Costs by Fuel Type and Size Bin *(2018-2021, not all outliers are shown)*

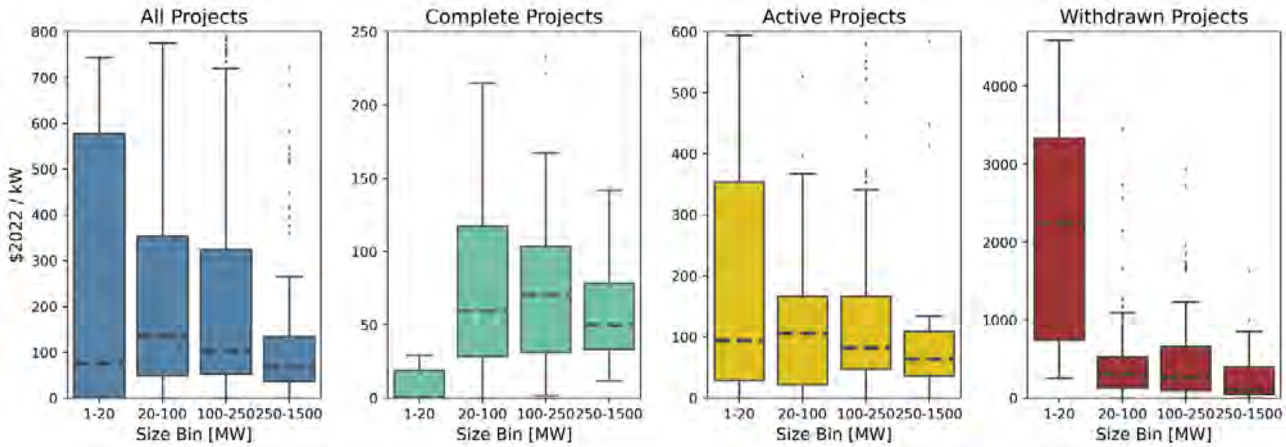

Figure 14 Total Interconnection Costs Request Status and Size Bin *(2018-2021, not all outliers are shown)*

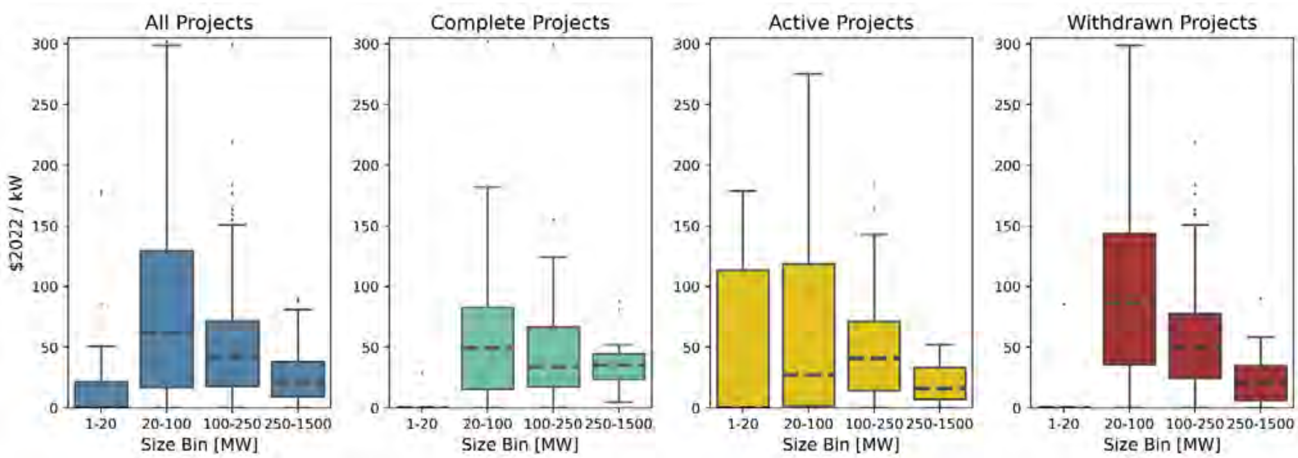

Figure 15 POI Interconnection Costs Request Status and Size Bin *(2018-2021, not all outliers are shown)*

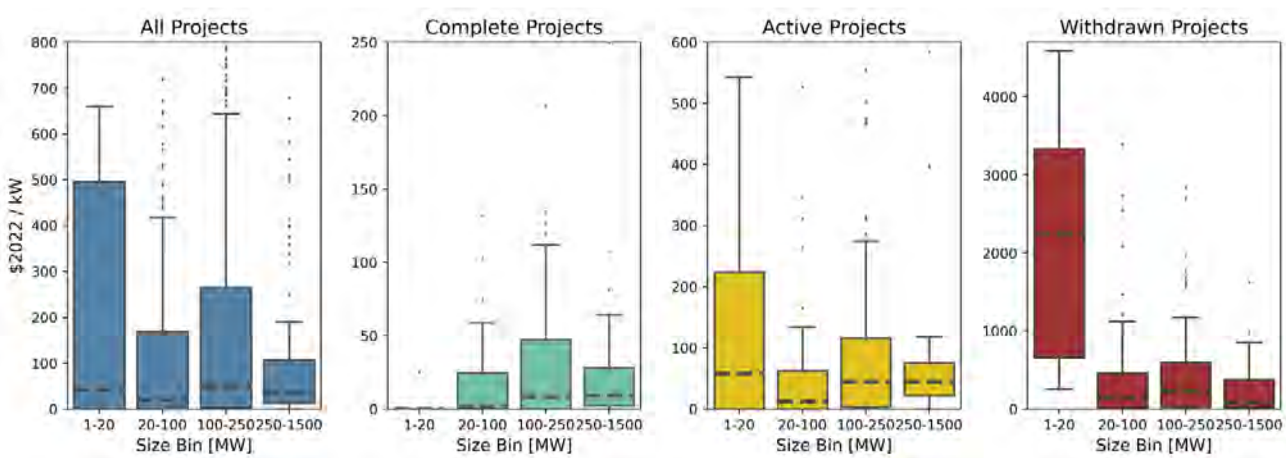

Figure 16 Network Interconnection Costs Request Status and Size Bin *(2018-2021, not all outliers are shown)*

Lessons from the Front Line:

Principles and Recommendations for Large-scale and Distributed Energy Interconnection Reform

Dave Gahl, Melissa Alfano, and Jeremiah Miller

June 14, 2022

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SEIA Solar Energy Industries Association®

I. Executive Summary

The United States solar industry continues to rapidly expand, but outdated interconnection policies pose a major threat to solar and storage deployment across the nation. Because solar power is one of the lowest-cost resources for electricity and because solar paired with storage is also a way for customers to supply their own clean power and save money when compared with distribution utility costs, applications to interconnect solar and energy storage projects have skyrocketed.

Interconnection policies in regional transmission organizations ("RTOs"), vertically integrated utilities, and distributed utilities have not kept pace with the demands of this new energy marketplace. Interconnection procedures designed for the by-gone thermal generation era are not aligned with today's advanced technologies, and interconnection delays now constitute a major threat toward meeting state and national clean energy goals.

This paper advances a series of reform principles, as well as near-term and longer-term interconnection reform recommendations. With respect to general reforms that impact large-scale and distributed projects SEIA recommends that utilities and RTOs:

- Add staff, adhere to interconnection timelines, and advance needed policies related to planning, forecasting, and standards to ensure progress is made toward state and national clean energy goals;
- Automate and standardize processes where appropriate; and
- Collect more information about infrastructure upgrade costs for all types of projects and make them accessible to developers.

With respect to interconnection reform for large-scale projects, SEIA recommends that the Federal Energy Regulatory Commission ("FERC") standardize queue management requirements across RTOs and require each RTO to:

- Make better transmission system operating information more accessible to interconnection customers; and
- Explore alternate models for paying for network upgrade costs.

With respect to interconnection reforms for distribution level projects, SEIA recommends that state regulators require each distribution utility to:

- Improve and open the black box of distribution system planning and perform proactive forecasting and scenario development to meet state clean energy goals; and
- Provide greater transparency and accuracy of interconnection estimates of infrastructure upgrade costs using hosting capacity maps, through the study process, or through preapplication processes.

State regulators should also:

- Reform cost sharing for infrastructure upgrades and split costs between interconnection customers and other system beneficiaries; and
- Increase project maturity requirements for projects to enter the interconnection queues.

Finally, as smart grid technologies continue to be deployed, RTOs, vertically integrated utilities, and distribution utilities should stop solving for grid constraints that only exist in the system under limited conditions and start providing more flexible interconnection solutions that take the use of these technologies into account.

II. Inadequate Interconnection Policies Pose a Major Threat to State and Federal Decarbonization Goals

Encouraged by state and federal policies, solar markets across the nation have seen tremendous growth. The solar industry installed more than 20 gigawatts ("GW") of capacity in 2021, with utility scale projects accounting for 17 GW.[1] Distribution level projects have also been growing steadily as well, and now nearly 5 percent of viable homes for solar have residential solar systems.[2] Even with expected headwinds for many clean energy projects around the country with an average annual growth rate of 33 percent over the past several years, analysts still forecast increasing solar deployments, and solar paired with energy storage resources, for some time to come.[3] Because solar is now one of the lowest cost sources of electricity, and because customers can supply their own power with on-site solar resources, applications to interconnect large-scale and small-scale solar projects have skyrocketed.

In the PJM Interconnection L.L.C. ("PJM") alone, a large-scale power market that includes 13 states and the District of Columbia, approximately 153 GW worth of energy projects are waiting for interconnection agreements.[4] Based on the backlog, PJM has stopped accepting new interconnection applications for a year to focus on processing existing requests.

At the distribution utility level, companies building rooftop solar for customers and on-site projects for commercial customers have also increasingly seen interconnection delays. And the attractive sites capable of interconnecting larger distributed projects, such as community solar projects, without the need for major technology upgrades have dwindled. For example, despite an ambitious solar incentive program and aggressive

[1] *See* U.S. Solar Market Insight Report, 2021 Year in Review. Wood Mackenzie, SEIA. March 2022. p 5.
[2] Ibid.
[3] Ibid. These headwinds also include a very damaging trade petition at the U.S. Department of Commerce that would impose punitive solar import tariff and has temporarily frozen the solar market.
[4] *See* https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

clean energy goals, initially 900 megawatts ("MW") worth of Massachusetts solar projects were delayed in 2020 due to various interconnection study processes by the distribution utilities as well as the RTO. For some of these projects, there is no clear timeline for resolution.[5] Similar issues have emerged in Maine. Together, more than 1,300 MW worth of distributed solar projects remain stymied by interconnection bottlenecks in Massachusetts and Maine.[6]

Furthermore, large-scale solar projects are interconnecting to an aging transmission system built for fossil fuel-fired, central station power plants. Clean energy projects are coming online to replace these fossil fuel plants, but the retirement of a single centralized coal plant typically results in multiple solar projects, in different areas, coming on-line to meet system needs. And as a result, new transmission facilities are needed to allow those new projects to interconnect to the grid. This, and the fact that the transmission system is aging and requires the replacement of many transmission assets, has resulted in prohibitively high infrastructure upgrade costs. In other words, increasingly expensive improvements to the grid are needed to connect projects.

High upgrade costs are also now emerging on the distribution system as the number of less constrained interconnection points are dwindling in key states and bi-directional power flows are becoming the norm. These smaller-scale projects must also rely on an older, less functional grid, that was only designed only to transmit power from generators to end users, and not from multiple customer generators across the system.

If distribution utilities, vertically integrated utilities, and RTOs are going to reach state and national clean energy and greenhouse gas ("GHG") reduction goals, such as SEIA's goal to supply 30 percent of the nation's electric power by the year 2030, or the Biden Administration's goal to reduce economy-wide GHG levels approximately 50 percent by 2030, then legislators, regulators, and utility operators must adopt key interconnection reforms as soon as possible.

This paper explains principles that should guide reform, proposes near-term reforms to encourage the faster connection of distributed and large-scale projects, and lays the foundation for longer-term interconnection changes.

Failing to adopt meaningful interconnection reforms will slow progress toward efforts such as transitioning to electric vehicle fleets, switching to electric heating sources for buildings, and cleaning up the national electric generation fleet. Without more carbon-free sources of energy such as solar and storage to power these cars, buildings and homes, decision-makers will see many of their decarbonization goals go unrealized.

[5] There are also examples of approved distribution utility projects that have been subject to further study by the RTO leaving some projects in permanent limbo and without any clear timeframe for resolution.
[6] *See* U.S. Solar Market Insight Report, 2021 Year in Review. Wood Mackenzie, SEIA. March 2022. p 31.

III. Three Interconnection Reform Principles

Based on extensive discussion with leading SEIA member companies, outside interconnection experts, and SEIA's on-the-ground experience, the following three principles should guide all interconnection reform discussions at both the RTO and utility level.

a. Interconnection Processes Must be Detailed, Transparent, and Clear

Any entity that oversees the interconnection of solar and storage projects must establish rules with clear, enforceable timelines for key activities. Regulators must establish detailed timeframes for the utilities or RTOs to process applications, complete project impact analyses, ensure the timely construction of interconnection infrastructure and conduct final inspections before energizing the project. Further, utilities and RTOs should provide infrastructure upgrade cost estimates that are as accurate as possible and estimates for infrastructure upgrades needed before interconnection, as soon as practicable in the interconnection process.

Relatedly, distribution utilities, vertically integrated utilities, and RTOs should publish more information about areas on the bulk power grid, and on the distribution utility grids, where power projects of all sizes could help meet system needs. This information should be available upon request to any interested stakeholder, as well as updated regularly. Not only is this information useful to energy project developers, but it would also help regulators, customers, and businesses seeking clean electricity.

b. Interconnection Rules Must Be Rigorously Enforced

The rules regarding tasks, timelines, and responsibilities should be rigorously enforced by oversight entities. Policies to improve performance, including penalties, should be used to ensure utilities are meeting and conducting timely studies and interconnecting large and small generators. To avoid penalties, based on our interviews and experience, too often distribution utilities will unilaterally "stop the clock," for a variety of reasons, resetting interconnection timelines with little explanation of delays or transparency regarding new targeted dates. At the large-scale level, long delays in RTOs processing requests based on lack of staff create a vicious cycle when large numbers of projects unable to stay in the queue for three to four years, withdraw from the queue, creating cascading restudies from those withdrawals, and further delay the processing of interconnection requests. Tariffs set timelines for processing interconnection applications, but then only hold utilities and RTOs to the "reasonable efforts" standard, a standard that FERC has never found to be violated.[7] Distribution utilities often rely on the outdated practice of conducting studies sequentially without following industry best practices to manage multiple applications at once in a timely and efficient manner. As a

[7] *See Tenaska Clear Creek Wind, LLC v. Southwest Power Pool, Inc.*, 177 FERC ¶ 61,200 (2021) (Clements Dissent at p 1).

result, an interconnection application can remain on hold for a long time before a study is commenced.

Utilities should not be able to simply reset interconnection timelines based on updating analysis that is only indirectly relevant to the project, or simply because they have too many applications to consider. Regulators must hold utilities and RTOs to a higher standard for processing interconnection applications, and provide the adequate incentives, or disincentives, for utilities and RTOs to process interconnection requests in a transparent and timely manner.

c. Infrastructure Upgrade Cost Estimates Must Be Reasonable, Directly Related to the Connecting Project, and Durable

When an infrastructure upgrade is needed to connect a project, either on the distribution system or the transmission system, the cost estimate that is provided to the interconnecting customer must be reasonable, transparent, and reflect the costs needed to connect safely to the grid. Such upgrade costs must also be commensurate with the project in terms of size and geography.

For example, for a distributed project grid upgrade costs should not be based on assumptions that the project and the accompanying upgrade would result in complete protection against total transformer and system failure. This kind of over-protection and system gold plating only drives up cost and kills projects.

Furthermore, for large-scale projects, analyses related to system impacts of connecting a project should be limited to areas on the transmission system that are most likely to be affected by the new resource, not distant RTO zones or utilities that would only be affected during a widespread system failure.

Lastly, for both large-scale and distributed projects, in cases where preliminary assessments of costs are provided, the final costs must be “durable,” or in other words, within a reasonable range of the initial estimate. Too often, developers run into issues where an infrastructure upgrade cost is identified, but final cost estimates or actual installation costs balloon to several times the initial estimate with little oversight; significantly impacting the economics of the project and in many cases causing the project to drop out of the queue.

IV. General Recommendations for Interconnection Reform

The following reforms are applicable to both transmission and distribution interconnections.

a. Encourage RTOs and Utilities to Recruit and Maintain Staff

The RTOs and utilities need to add staff to process applications, work through issues, conduct studies, and move projects through the queue faster than ever before.[8] RTOs and utilities need to forecast resourcing needs proactively in response to climate goals and regulatory programs and hire adequate interconnection support and engineering staff, redeploy existing staff, and generally prioritize this work. RTOs and utilities need to ensure there is adequate capability to deal with increased interconnection requests to the distribution and transmission system, in addition to evolving transmission and distribution planning needs that may require additional or shared functional staff to support the climate goals of the state and/or region.

b. Require Adoption of State-of-the-Art Study Processing Methods

Utilities and RTOs should create automated, web-based portals for submitting interconnection requests and for rapid information exchange. These web portals should include centralized, searchable databases for commonly asked questions, lessons learned, and standardized data collection and entry. To the extent possible, utilities and RTOs should develop automated processes for application intake, studies, and project modification submissions, to reduce delays associated with lags in information exchange and review between interconnection process stakeholders.

Relatedly, the RTOs and distribution utilities should move toward publishing interconnection queues that provide *real-time* updated information on the queue itself, so the market has insight into project status as well as metrics that show how quickly or slowly projects are moving through the interconnection process. This real-time information would help developers and customers and allow stakeholders to more accurately forecast construction timelines for new resources on the system. Regulators should require utilities and RTOs to report these data to track and monitor their progress and for use in measuring performance and for enforcement.[9]

c. Collect Infrastructure Upgrade Cost Data

Although a number of states collect information on interconnection upgrade costs for completed projects, to our knowledge no state or RTO is systematically collecting information on interconnection project estimates for *all* complete project applications or the corresponding *estimated* costs to interconnect those projects.

High interconnection costs can be the difference between a project moving forward or being withdrawn. Furthermore, monopolistic utilities have historically no incentive to provide accurate or transparent costs to better inform customers throughout the interconnection process. Based on our members' experience, utility cost estimates do not often correspond to market prices for materials or labor and therefore transparency into additional utility "adders" or "overheads" would provide needed insight into how

[8] State regulatory agencies should also dedicate more staff to providing oversight of utility interconnection work.
[9] *See Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (2018), *errata notice*, 167 FERC ¶ 61,123, *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137, *errata notice*, 167 FERC ¶ 61,124, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019).

utilities arrive at their cost estimates. More comprehensive data should be collected and reported that shows interconnection infrastructure upgrade costs assigned to pending, active or withdrawn projects in the queue, including:

- The estimated cost of interconnection facilities and/or network upgrades associated with the project;
- The actual cost of interconnection facilities and/or network upgrades associated with the project; and
- A breakdown of the interconnection delays by transmission zone, or feeder line, to determine whether there is a particular transmission owner or utility associated with the interconnection delays.

These data points would be tremendously useful to interconnection customers and would help educate the market about system needs, as well as provide more useful information to regulators about the state of the grid itself.

d. Consider Interconnection Reforms Alongside Updated Clean Energy Policies

Based on our direct experience in key states, policymakers and regulators should ensure that interconnection policies evolve and keep pace with changing clean energy goals. For instance, when a state enacts policies to: create a community solar program, adopt incentives to encourage distributed solar, increase renewable energy procurements, or increase its renewable or clean energy portfolio standard obligations, decision-makers should also be thinking about the needed changes to interconnection to make achieving the goal possible.

Too often states have passed ambitious laws and watched their implementation timelines slip and programs run into trouble because policymakers failed to consider outdated interconnection rules. These delays have serious consequences, including freezing development capital, increasing project transaction and financing costs, and slowing the deployment of clean energy. At the very least, policymakers should always direct regulators to review interconnection rules when they are making any major changes to clean energy policy, if not outright direct specific additional reforms with hard timelines for implementation.

V. NEAR-TERM LARGE-SCALE INTERCONNECTION REFORMS

For large-scale solar and storage projects, the following recommendations apply to needed interconnection changes in RTO and vertically integrated transmission utilities.[10]

a. Provide System Operating Data and Study Assumptions to Project Developers

More transparent and more granular transmission system information is an important element to improving the large-scale interconnection processes. The transmission planning process should provide more information to generation developers on points of interconnection with the lowest likely interconnection costs. Generation developers suffer from information asymmetry with respect to project siting. Project developers do not know how costly network upgrades will be until they are far along in the interconnection process—so to obtain this information, projects need to enter the interconnection queue. This is inefficient for project developers and for transmission providers.

Instead, transmission providers should make available, on a secured website, the following:

- Study models and assumptions that will be used for each cluster of projects to be studied;
- A list of the transmission lines that are currently capacity-constrained and a list of lines expected to be constrained once certain projects in the queue come online;
- Information on transfer capability and points of interconnection of planned transmission; and
- A database of FERC jurisdictional distribution and sub-transmission lines to clarify the interconnection rules to which the interconnection customer would need to follow.

This information, coupled with the requirement to provide interconnection customers with the option of using third-party consultants to produce required studies, would help unclog interconnection queues by encouraging better project planning by developers and eliminating the need for these "exploratory" requests. [11]

b. Standardize Queue Management Requirements

The slow pace of completing interconnection studies is increasingly becoming a major roadblock to bringing large-scale resources online. Study timelines vary by RTO, but

[10] Reforms related to large-scale interconnection reforms were first proposed by SEIA, along with American Clean Power and Advanced Energy Economy in comments submitted to FERC on February 14, 2022. *See* Comments of the Clean Energy Coalition, FERC Docket No. RM21-17 (Feb. 14, 2022). This whitepaper elaborates on several proposals in the February FERC comments.
[11] *See* section V.c. infra. p 10.

large-scale projects are often forced to spend significant upfront capital and then wait sometimes up to five years, in the case of PJM, for studies to be completed.

While FERC Order No. 2003 and Order No. 845 show that there is a need for independent entity variations in certain instances, there are certain queue management practices that are unrelated to geographical and market differences that could be standardized across the regions. These include:

- Standardizing interconnection milestone requirements for receiving applications, maintaining progress through the application process, or suspending queue positions.
- Establishing a "first-ready, first-served" process, and requiring projects to demonstrate project readiness earlier in the process. These demonstrations would include:
    - site control;
    - a demonstration of permitting progress, either filed applications or received permits;
    - an executed power purchase agreement or other significant financial agreement to show project viability; and
    - the payment of "gated" deposits that increase as the project moves through the review period.
- Standardizing interconnection study deposits from developers, as well as procedures and penalties for project withdrawal.
- Requiring that utilities use the same assumptions for interconnection studies that they use in their transmission planning studies.

c. Explore New Models for Paying for Network Upgrade Costs

There are several proposals before FERC today involving revisiting the question of who pays for the required network upgrades to interconnect large-scale projects. Under most tariffs, the interconnection customer pays 100 percent, or nearly 100 percent, of these costs. So called "participant funding" was intended to address certain concerns, including the efficient siting of resources.[12] Consumer advocates often view participant funding as a way to protect retail ratepayers from the cost of network upgrades.

However, with the change in resource mix, and the lack of significant upgrades to the transmission system, those concerns are not as prevalent as they once were. The efficient siting of renewable resources not only includes access to transmission, but also siting in areas that would provide optimal access to solar and wind injections.

[12] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, P 695 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

Going forward, FERC should do away with the participant funding and crediting mechanism entirely, instead requiring transmission providers to establish a fee, separate from any interconnection deposit, based on project size, to be charged for submitting an interconnection request.[13] For projects that require network upgrades, the fee would be applied towards the cost of the network upgrades. The remaining cost of the network upgrade would be allocated to the load zone served by the project.[14]

d. Reform the Transmission Planning Process

While reforming the interconnection process is necessary, the queue backlogs generators currently face are just symptoms of a flawed transmission planning process. On April 21, 2022, FERC issued a Notice of Proposed Rulemaking that would require RTOs and transmission utilities in non-RTO regions to engage in long-term, forward-looking planning that incorporates factors, such as federal, state, and local laws and regulations that affect the future resource mix and demand; trends in technology and fuel costs; resource retirements; generator interconnection requests and withdrawals; and extreme weather events.[15] The demand for clean energy will continue to grow. States will continue to set clean energy goals. Large, sophisticated customers will continue to demand clean energy.[16] Better transmission planning that encourages new transmission to serve growing demand from a diverse set of resources will help address many of issues causing the interconnection queue delays.

e. RTO/Utilities Can Head Off Affected Systems Problems

Furthermore, the RTOs and utilities should proactively engage affected parties to find proactive solutions when affected system issues arise. Project developers occasionally run into roadblocks when, upon analysis, their project is projected to have an impact on a neighboring transmission system. RTOs/utilities, however, can come up with solutions to these kinds of problems without waiting for FERC or another utility to act. When RTOs/utilities work together to plan for seams issues triggered by a large-scale project ultimately more clean energy projects can be interconnected to the grid based upon joint

[13] *See* Comments of the Solar Energy Industries Association, Docket No. RM21-17 (Oct. 12, 2021).
[14] Should a fee structure not be implemented, FERC should adopt a methodology that encourages developer certainty for any cost allocation of upgrade costs, such as cost cap.
[15] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 179 FERC ¶ 61,028 (2022).
[16] *See* Amazon, Renewable Energy, https://sustainability.aboutamazon.com/ (establishing a goal of 100% renewable energy by 2025); Walmart, Setting Records, Walmart Continues Moving Toward Becoming a Totally Renewable Business, https://corporate.walmart.com/ (establishing a goal of 100% renewable energy by 2035); Apple, Apple powers ahead in new renewable energy solutions with over 110 suppliers, https://www.apple.com/newsroom/2021/03/apple-powers-ahead-in-new-renewable-energy-solutions-with-over-110-suppliers/ (establishing a goal of a carbon neutral supply chain by 2030); *see also* Rich Glick, Matthew Christiansen, FERC and Climate Change, 40 Energy L.J. 1, 8 (2019).

transmission projects.[17] By working collaboratively with developers, grid managers can unlock tremendous value for customers.

VI. NEAR-TERM DISTRIBUTED UTILITY REFORMS

a. Improve Distribution System Planning and Prioritize Climate Goals

Any discussion of interconnection reform by distribution utilities must begin with the need for better, more transparent, distribution system planning. Even leading states that have put effort into improving the distribution planning process, such as New York, have a long way to go toward making the distribution planning process more in-line with the needs of a modern utility system.

Planners must look at the exercise through the lens of envisioning a decarbonized grid, maintaining reliability and promoting grid resilience. Transparent and proactive distribution system planning would provide project developers insight into utility operations, steer projects to locations on the grid that would help improve resiliency, support future electrification, or defer massive infrastructure upgrades. Thoughtful planning can ensure that infrastructure is built to serve the needs of the state instead of becoming a bottleneck on the pathway to decarbonization.

Ideally, through the distribution planning process the utility would forecast distributed energy resource ("DER") growth, identify saturation points on their systems, and then plan a combination of cost-effective solutions to improve reliability and increase hosting capacity. Solutions such as installing more DER and energy storage to offset or delay grid infrastructure and improve ratepayer benefits should also be considered.

Too often the distribution planning process is a "black box" which provide market participants very little input or insight.[18] Regulators should require utilities to open this box and include the industry and other distribution-system users in early discussions regarding forecasts, scenarios, market trends, and technology and technical assumptions. Too often utilities simply retreat behind closed doors, produce their plans, and drop them on the stakeholder community, as well as regulators with very little explanation or opportunity to meaningfully engage. Although better system planning will not solve every interconnection problem, better planning will help improve the accuracy of estimating interconnection upgrade costs and would be helpful when considering changes to cost sharing.

[17] Michael Goggin, Rob Gramlich, Michael Skelly, Transmission Projects Ready to Go: Plugging in to America's Untapped Renewable Resources, at 4 (April 2021), https://cleanenergygrid.org/wp-content/uploads/2019/04/Transmission-Projects-Ready-to-Go-Final.pdf

[18] *See* https://www.seia.org/sites/default/files/resources/SEIA-GridMod-Series-2_2017-July-FINAL_0.pdf

b. Provide Accurate Estimates of Infrastructure Upgrade Costs Up Front Or Use a Preapplication Report

Ideally, enough system information and accurate hosting capacity maps would be available to allow developers to make informed decisions about whether to pay the required interconnection upgrade costs. If a developer knows upgrade costs will run from $500,000 - $1,500,000 they may choose to avoid a full application process, saving the need for more exhaustive studies and analysis.

However, where that information is not yet available distribution utilities should establish a low-cost, pre-application process for DER project developers that may be used as a screen to understand potential interconnection upgrade costs. Project developers should be able to submit a pre-application proposal to the utility that scopes out the project location, size, configuration, and interconnection point. The proposal should yield a durable estimate of the interconnection upgrade cost needed at that site to safely connect the project. This is a no-regrets approach, employed by at least 12 states, that could save project developers and utilities considerable time and effort later in the interconnection process.[19]

These initial estimates, while they can be transmitted in ranges of likely costs, should also be reasonable. The final costs should not be significantly higher than the initial estimate. Too often, projects receive the final cost estimate near the end of the development process that is orders of magnitude greater than the initial estimate, resulting in the developer withdrawing the project from the queue. Establishing a pre-screening process can prevent the inefficiencies resulting from late-stage withdrawals.

c. Reform Cost Sharing for Infrastructure Upgrades

A major issue in distribution utility upgrades involves the problem of sharing costs among multiple DERs that benefit from an infrastructure upgrade. Under the current practice, the project developer, not the utility, pays for any upgrade needed to connect their project. This practice sometimes results in benefits not just to the interconnection project owner, but also to the customers of the utility. But these benefits also accrue to subsequent interconnection customers as well, often creating a free-ridership issue that is becoming a critical barrier to renewable energy deployment. There are several issues with this model that need to be revisited.

1. First Mover Problem

Under the first mover problem, one project developer makes an initial investment in interconnection network upgrades that ultimately results in benefits to several, subsequent interconnection customers. For example, developer A pays $1 million for an infrastructure upgrade to connect their project, which results in additional capacity for connection on the distribution grid. Then developer B connects their project to the same

[19] *See* Zachary Peterson and Eric Lockhart, Evaluating the Role of Pre-Application Reports in Improving Distributed Generation Interconnection Processes, https://www.nrel.gov/docs/fy19osti/71765.pdf.

location, without incurring these costs, instead benefiting from the upfront investment made by developer A.

Unless a developer agrees to pay the infrastructure upgrade costs, much needed clean energy capacity is unlikely to be installed on the grid in the first place. With upgrade costs increasing on a year-to-year basis, significant amounts of DERs are not being developed because no developer is willing to pay interconnection upgrade costs that are higher than project returns. Given the magnitude of the challenge at hand, regulators need to come up with a better way to unlock areas on the grid that accommodate more distributed resources.[20]

To solve the first mover problem, first state regulators should consider revising who pays the costs for infrastructure upgrades. Additionally, regulators should establish a set amount of interconnection upgrade costs developers should pay and split remaining costs with the broader class of utility ratepayers who are also benefiting from the upgrade. Although establishing the developer contribution would require more technical analysis, this approach would help unlock much more clean energy potential on the grid and is under consideration in some jurisdictions. For example, Massachusetts is considering a model where developer contributions would be set on a $/kW basis that is known in advance of applying for interconnections, with a portion of potentially being socialized among utility ratepayers. This proposal has considerable promise and should be replicated in other states.

2. Unfair Cost Allocation Problem

The second issue involves fairness and we return to our example. Developer B benefits from the grid improvement paid for by developer A. Unless developer A paid in the first instance, any remaining projects wouldn't even be able to interconnect at all, let alone serve the need for their customers. Let's call this the "unfair allocation" problem. There are drawbacks to this approach. The first interconnection firm is still responsible for the entire cost of the upgrade, placing all the risk on the first developer. And some upgrade costs are so large that virtually no project by itself or jointly, can pay for the needed improvement.

To solve the "unfair allocation" problem, a few states have experimented with different approaches. Going back to our example, New York authorized developer A to collect a portion of the paid upgrade costs from developer B on a pro-rata basis. Connecting firms would be required to pay the firm making the initial upgrade, and any subsequently interconnecting firm would reimburse the first two firms. To date, however, this collection method was seldom used. As a result, in a second round of interconnection reforms, New York then authorized utilities to pay for the cost of upgrades in the first instance, and then collect from developers their pro rata share.

[20] Note that this problem will happening more frequently in utility territories as the low-hanging fruit of easy interconnection sites are taken.

Now Massachusetts is considering a similar approach. However, with the Massachusetts model, the utility pays the upgrade costs in the first instance and the utility charges firms on a pro-rata basis their share of the cost upgrade after interconnection, with ratepayers paying for the costs in the interim and being reimbursed as new projects pay their pro-rata fee.

d. Increase project maturity requirements for large DG

Finally, similar to our recommendation for transmission system projects, distribution utilities should establish a "first-ready, first-served" process, requiring projects to demonstrate project readiness earlier in the process. To enter the distribution utility queues after the preapplication stages, projects should be required to show a) site control, b) detailed design specifications, and c) the developing firm should be required to pay up front deposits.

These maturity requirements ensure that serious projects enter the queue and have a better chance toward reaching commercial operation, instead of more speculative projects that would waste the utility's time conducting studies when they have very little chance of reaching fruition.

VII. Long-Term Interconnection Reforms

The recommendations considered above should be considered near-term objectives for reform and will help RTOs and utilities improve their processes and make progress toward achieving state and federal policy goals. These are immediate steps that will help speed up the connection of clean energy resources.

But in the long run, even these common-sense improvements will be insufficient to drive the rapid interconnections that will be needed to completely decarbonize the electric system and meet the demands of growing electric load. After quickly executing on the near-term reforms, regulators should begin considering more systemic changes for both RTOs, vertically integrated utilities, and distribution utilities.

One concept that regulators should consider is providing "flexible" interconnection options to large-scale and small-scale clean energy resources. A flexible interconnection agreement connects the resource without major infrastructure upgrade cost but uses controls to monitor the state of the grid at any given time and adjust the project's output to respond to changing conditions.

While flexible interconnection has become standardized in some European countries, only a variety of small demonstrations have taken place in the US. New York stakeholders are potentially the furthest along, where Avangrid worked with Smarter Grid Solutions to connect large-scale solar to constrained distribution feeders. Their Spencerport solar projects were initially approved for only a combined 2.6 megawatts of firm connection. Using the flexible interconnection framework enabled 15 megawatts to connect.[21] As these projects demonstrate, providing flexible interconnection choices, coupled with smart grid technology investments, can provide interconnections solutions when typical approaches are cost prohibitive. New York stakeholders are now actively considering demonstration options from all the other utilities and are considering revisions to add flexible interconnection to their standardized interconnection requirements.

Today's interconnection procedures are organized around the concept that headroom or hosting capacity is limited based on static, snapshot of worst-case conditions. Regulators must keep in mind, however, that most parts of the grid have approximately 50% utilization annually. To a great degree, grid constraints are rare operating conditions compared to annual availability of most transmission or distribution lines. Instead, more aggressive deployment of smart grid technologies and grid management tools could avoid the need for many infrastructure upgrades.

In brief, in thinking through long-term interconnection reforms, regulators and utilities should be looking at the entire range of options to modernize that grid, not simply infrastructure upgrades, reconductoring lines, or building new substations, and come up with options for interconnecting projects that take customer flexibility and these newer technologies into account.

The same concept applies on the distribution grid. Market choice for firm versus flexible interconnection is equally applicable for in front of the meter large, distributed generation, and even for large behind the meter systems too. Small, distributed generation, less than 25 kilowatts, for residential and small business should aim to be further streamlined by moving to a "connect and notify" approach. This way controllable generation and storage are treated fairly with small customers connecting new controllable loads like electric vehicle charging or heat pumps.

With a more actively managed grid, RTOs and utilities would prioritize smart grid and customer flexibility solutions as the most affordable ways to modernize the electric system. Therefore, providing developers with the choice between firm versus flexible interconnection options on how to connect to "constrained" networks may lead to better outcomes, and potentially significant savings for ratepayers.

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[21] *See* Renewable energy generation boosted by more than 100% in US-first demonstration project (Dec. 8, 2021). https://www.powermag.com/press-releases/renewable-energy-generation-boosted-by-more-than-100-in-us-first-demonstration-project/

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Improvements to Generator Interconnection Procedures and Agreements **Docket No. RM22-14-000**

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

Pursuant to the June 16, 2022 Notice of Proposed Rulemaking,[1] the Solar Energy Industries Association ("SEIA") submits these comments on the Commission's proposed reforms to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies.

SEIA represents independent power producers both in and outside of organized markets. Since the Commission issued Order No. 2003,[2] SEIA and SEIA members have been active participants in interconnection proceedings before the Commission.[3] Along with member companies, SEIA also worked in stakeholder processes across the country to help address some of the major issues within interconnection queues. The comments and recommendations below represent the experiences of a wide range of member companies who faced, and continue to face,

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[1] *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (2022) ("NOPR").

[2] *Standardization of Generator Interconnection Agreements & Proc.*, Order No. 2003, 68 FR 49845 (Aug. 19, 2003), 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932 (Mar. 5, 2004), 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 19, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 70 FR 37661 (July 18, 2005), 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007) (*NARUC v. FERC*).

[3] *See* Comments of the Solar Energy Industries Association, Docket No. ER22-2110 (July 14, 2022) (PJM Interconnection Reform Filing); Joint Supplemental Comments of the American Clean Power Association, Advanced Energy Economy, the Solar Energy Industries Association, and the American Council on Renewable Energy on Generation Interconnection Queue Processing and Cost Allocation Reforms, Docket Nos. AD21-15 and RM21-17 (Feb. 14, 2022); Protest of Solar Energy Industries Association, Docket No. ER20-294 (July 17, 2020) (PacifiCorp Queue Reform); Comment of Solar Energy Industries Association, Docket No. RM17-8 (April 13, 2017) (Order No. 845 proceeding).

interconnection queue backlogs. SEIA represents an industry that needs to address these issues and an industry that is willing to do what it takes to solve them.

SEIA strongly supports many of the reforms in this proposal. Providing better information to interconnection customers earlier in the interconnection process will lead to better siting decisions and reduce network upgrade costs. Further, reforms such as moving to a cluster study process, sharing network upgrade costs, eliminating the "reasonable efforts" standard, standardizing affected system studies, and incorporating advanced technologies into the interconnection process, will provide more certainty in the process, leading to fewer withdrawals. SEIA also supports several of the reforms that would increase the requirements to enter the queue, such as higher study deposits and site control requirements, as these may help identify the more viable projects earlier in the process.

However, several aspects of the NOPR impose requirements on interconnection customers that are unduly burdensome and may be infeasible for certain solar developers. The proposed rule proposes that interconnection customers provide either (1) demonstration of firm contractual obligations for the sale of the generating facility's energy, capacity, or ancillary services, or the sale of the constructed generating facility itself; or (2) a commercial readiness deposit based on the interconnection customer's place within the cluster study process, which is returned if the interconnection customer demonstrates commercial readiness later on. SEIA supports allowing projects to demonstrate commercial readiness through means other than having finalized power sale contracts. Independent power producers would be challenged to enter into binding contractual sale obligations without having any reasonable certainty into their final interconnection costs. To that end, SEIA believes the final rule should allow developers to demonstrate commercial readiness through means other than firm contractual sale contracts or financial deposits. Commercial readiness should be evaluated based on the totality of circumstances, and should be required later in the process, so to avoid injecting uncertainty into the interconnection process.

SEIA urges the Commission to swiftly issue a final rulemaking in this proceeding that will implement efficient reforms to the interconnection process, while also leveling a playing field that is inherently unfair to interconnection customers. Reforms that provide for more transparency and certainty in the process will lower interconnection costs and ultimately reduce costs for consumers.

I. COMMENTS

A. Reforms to implement a first-ready, first-served cluster study process

1. The proposed informational interconnection study will provide information of limited value to interconnection customers while draining limited RTO resources.

SEIA supports reforms that will introduce more transparency into the interconnection process. A more transparent process will lead to better decisions by the interconnection customer and create more certainty and stability in the process. While SEIA appreciates that the Commission recognizes the lack of information available to interconnection customers at the time they enter the queue, SEIA does not support the proposal to require transmission providers to conduct informational studies for prospective interconnection customers. Such studies would be a drain on limited transmission provider resources, would not produce useful information for interconnection customers, and are redundant of the due diligence already required interconnection customers.

These studies would overburden limited transmission provider resources. In the transmission NOPR proceedings, several transmission providers noted that they have limited staff resources.[4] These comments have been echoed during stakeholder proceedings and other filings.[5] SEIA understands these concerns, and our members have experienced the effects of these staffing issues. By using limited transmission provider staffing resources, these studies could result in a longer interconnection queue process, as it ties up resources for conducting actual interconnection studies. SEIA sees no need to require transmission providers who are not already conducting these studies to expend their limited resources doing so, especially given the limited value of the studies.

These studies are of limited value to the interconnection customer. Under the proposed reform, the informational studies would provide (1) circuit breaker short circuit capability; (2) voltage overloads; and (3) "estimated network upgrade costs related to the identified overloads and violations."[6] Network upgrade costs are not a function of a single project: They are a function of *all* the projects within a cluster. Because the studies are designed to help *prospective* interconnection customers, they do not necessarily represent the interconnection customers that will ultimately be in the studied cluster, nor the network upgrades the interconnection customers in the cluster would be responsible for. The intent of this proposed reform is to provide cost estimates for the transmission provider's interconnection facilities and network upgrade costs.[7]

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[4] Comments of the Midcontinent Independent System Operator, Inc., at 15, Docket No. RM21-17 (Aug. 17, 2022) (noting that "limited staff resources" may hinder compliance with a new transmission planning rule); Initial Comments of PJM Interconnection, L.L.C. at 12829, Docket No. RM21-17 (Aug. 17, 2022) (explaining how PJM is in the process of expanding its staff in order to address long-term planning).

[5] *Cal. Indep. Sys. Operator Corp.*, 176 FERC ¶ 61,207, P 21 (2021).

[6] NOPR P 46.

[7] *See* NOPR P 42.

But without knowing what other projects will be in the same cluster as the studied project, the studies will not result in an accurate representation of the network upgrade costs for which an interconnection customer may be responsible.

In doing their due diligence, interconnection customers routinely assess Available Transmission Capacity and conduct various studies to guide them in project siting decisions and in determining whether to submit an interconnection request in the first place. These studies produce useful information, but they can be better, and better due diligence models will result in more efficient siting decisions and ultimately lower network upgrade costs. To make these models better, SEIA requests that the Commission, instead of requiring transmission providers to conduct pre-request studies, require transmission providers to provide previous cluster studies and models to interconnection customers, subject to a confidentiality agreement. Preparation and due diligence lead to viable interconnection requests. Providing the information to better perform that due diligence will help ensure the viability of the projects entering the interconnection queues.

2. Publicly posted information about bus-level interconnection capacity will be useful in helping independent power producers in making siting decisions.

SEIA supports requiring transmission providers to publicly post information about bus-level interconnection capacity constraints. Understanding where constraints are, and where network upgrades will likely be necessary, helps interconnection customers make more efficient siting decision, and ameliorate the incentive to submit multiple exploratory requests.[8]

[8] NOPR P 49; *see also* Order No. 2003, 104 FERC ¶ 61,103, P 695.

Unlike the proposed informational study requirement, requiring transmission providers to give information about transmission capacity does not impose a significant additional burden on transmission providers. As the Commission stated in the NOPR, the Midcontinent Independent System Operator, Inc. (MISO) already provides an interactive heatmap of expected congestion.[9] The PJM Interconnection L.L.C. (PJM) is currently in the process of developing and implementing its *Queue Scope* screening tool, which "screens potential points of interconnection (POI) on the PJM system by assessing grid impacts based on the amount of MW injection or withdrawal at a given POI."[10] These are tools that help interconnection customers make better siting decisions in the first place, and SEIA urges the Commission to adopt this reform in the final rule, with the following modifications:

- Allow the transmission providers flexibility in the way the information is presented. Whether the final product is a visual representation, like MISO's heatmap, or some other product, is not as relevant as the information provided by the product.
- Require transmission providers to use both the most recently available study models in creating the results, as well as the model used in the most recently completed system impact study.
- Require transmission providers to include more information regarding the hosting capacity, circuit strength, and harmonics of transmission system elements. If any such information is considered Critical Energy Infrastructure Information, then the transmission provider should make it available subject to any necessary confidentiality agreements.

As the Commission recognizes, there is a lack of information available to interconnection customers.[11] The information produced through this proposed requirement would resolve some of the information asymmetry interconnection customers face today.

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[9] NOPR P 50, n.105.

[10] *See* Interconnection Screening Tool Overview, "Queue Scope," (Sept. 28, 2022), https://pjm.com/-/media/committees-groups/subcommittees/ips/2022/20220928/item-05---overview-of-queue-scope.ashx.

[11] *See* NOPR P 42.

3. Moving to a cluster study approach can result in a more queue processing, if coupled with a holistic interconnection reform.

SEIA supports the Commission's proposal to make cluster studies the required interconnection study method.[12] A transmission to a cluster study process with higher deposit requirements will help address several issues that lead to cascading withdrawals.

The Commission has long preferred clustering for conducting interconnection studies,[13] finding that it allows "for more efficient prioritization of interconnection requests while still providing protection from undue discrimination by transmission providers."[14] Clustering studies not only leads to efficient queue management, but it also reduces the likelihood that a project will withdraw from the queue because of high network costs. First-come, first-served processes shift the costs of network upgrades to the first project that triggers the upgrade.[15] SEIA members have often seen network upgrade costs double the initial estimated interconnection costs, resulting in a previously viable project becoming uneconomic. In a serial queue process, the network upgrade costs continue to shift to the next customer in the queue until they reach a customer that can pay.[16] A cluster process, however, allocates the costs of interconnection network upgrades among multiple projects, which would alleviate the financial burden of those upgrades on any one interconnection customer, which should lead to less project withdrawals.

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[12] *See* NOPR P 64.

[13] Order No. 2003, 104 FERC ¶ 61,103 at P 155; Order No. 2006, 111 FERC ¶ 61,220 at P 181.

[14] NOPR P 64; *see also Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 18 (2008).

[15] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 8 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.) ("Often one project would be assigned a high cost to upgrade the network, but then subsequent projects could utilize the capacity that project created, such that the subsequent project would be assigned a lower cost. When one project drops out, costs are typically shifted onto others, causing a domino effect of cancellations.").

[16] *See* PJM Interconnection Reform Filing, Connell Aff. at P 12.

To make the cluster study process more efficient, SEIA recommends that the Commission direct transmission providers to provide cost estimates at each stage of the interconnection process to allow interconnection customers to make more informed decisions earlier in the process. To further limit delays in the process, SEIA requests that the Commission add further certainty to the cluster study process by limiting the number of restudies the transmission provider may make for each cluster, with each restudy being limited to a 30-day period.[17]

In addition to these reforms, SEIA requests that the Commission specifically clarify that both project-specific and cluster Scoping Meetings must provide the option for Interconnection Customers to attend via teleconference, which is currently unavailable in all regions.[18] Already it can be difficult to coordinate in-person Scoping Meetings with just a single Interconnection Customer and transmission provider. Expanding this group with additional interconnection customers representing additional projects will compound this difficulty further. Greater certainty regarding the study timeline is critical because land use option rights, which are critical to maintaining queue position and to demonstrate commercial readiness, often expire if not exercised. Developers are particularly challenged when they are provided notice of study delay on the day before a completed study was expected in accordance with published interconnection procedures or study guidelines. To the extent project developers will be expected to adhere to

[17] *See* NOPR P 78.

[18] *See* NVEnergy, OATT, Attach. N, Sec. 1, Definitions ("**Application Meeting** shall mean the *in person* meeting held between the Transmission Provider and the Interconnection Customer during the Application Process in order to process the Application Request, to discuss any potential siting impediments or timelines associated with an Interconnection Customer's Application Request, and to create a Preliminary Plan of Development (if necessary) for the Interconnection Customer's Application Request.") (emphasis added).

higher standards of commercial viability, transmission providers also must be held accountable for excessive delays in completing interconnection studies.

4. To deter the submission of exploratory interconnection requests, the shared costs of the cluster studies should be 50% pro rata based on MWs and 50% per capita based on number of interconnection requests in cluster.

SEIA generally supports the Commission's proposal to allocate the shared costs of cluster studies based on the size of the projects in the cluster and the number of requests in a cluster.[19] As the Commission finds, it has accepted a variety of cost allocation approaches, from allocating entirely on a pro rata basis to entirely on a per capita basis.[20] In response to a large influx of new interconnection requests, the California Independent System Operator, Inc. (CAISO) proposed, and the Commission accepted,[21] a methodology that allocates all study costs equally based on the number of interconnection requests within the cluster.[22] Unlike CAISO, MISO allocates all study costs based on the number of MWs requested.[23] MISO proposed significant interconnection reforms in 2015 to address the growing number of projects in its queue,[24] but its study cost allocation methodology was in place several year before that.[25]

The Commission bases its 90% pro rata, 10% per capita proposal on cost causation principles, finding that "the MW size of a cluster has a dramatic impact on the cost of studying

[19] NOPR P 82.

[20] NOPR P 81.

[21] *California Independent System Operator, Inc.*, 140 FERC ¶ 61,070, P 4 (2012).

[22] CAISO, CAISO eTariff, OATT, app. DD, section 3 (14.0.0), section 3.5.1.2.

[23] MISO, FERC Electric Tariff, OATT, attach. X, (155.0.0) section 3.3.1.

[24] *See* MISO 2015 Queue Reform Filing, at 2, Docket No. ER16-675-000 (filed Dec. 31, 2015).

[25] *See* MISO filing Regarding Attachment X of its Tariff, Docket No. ER11-3583 (filed May 17, 2011) (showing the current per MW cost allocation methodology as tariff language already in place.)

the cluster, while also recognizing that the number of interconnection requests included in the cluster also impacts the cost of studying the cluster, but to a lesser degree."[26] The MW size of a cluster does impact the costs of studying the cluster, and the MW size of that cluster will be impacted by the number of requests in the queue. The MW size of the cluster may be artificially inflated when certain interconnection customers submit multiple exploratory requests.

SEIA recommends that the Commission set the default allocation of cluster study costs as follows: 50% of the applicable study costs to interconnection customers on a pro rata basis based on requested MWs included in the applicable cluster, and 50% of the applicable study costs to interconnection customers on a per capita basis based on the number of interconnection requests included in the applicable cluster. However, the Commission should allow transmission providers to propose other cost allocation methodologies that may be more suitable to their regions. Throughout the NOPR, the Commission consistently recognizes that there are many non-viable projects in the queue,[27] and transmission providers need to provide incentives to stop those projects from entering the queue in the first place, similar to the reasoning behind CAISO's study cost allocation methodology.[28] The Commission should maintain that approach here, and structure the cost allocation so that its customers with multiple projects are responsible for a greater share of the study costs. Increasing study costs for interconnection customers with more requests in a single cluster will reduce the incentive to submit non-viable requests.

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[26] NOPR P 82.

[27] NOPR PP 26, 30, 40, 49.

[28] *California Independent System Operator, Inc.*, 140 FERC ¶ 61,070, P 4 (2012).

5. A Proportional Impact Method of cluster network upgrade cost allocation should be coupled with a Commission-set minimum distribution factor level.

SEIA generally supports the proposal to allocate network costs within a cluster based on proportional impact.[29] As explained above, first-come, first-served processes shift the entire costs of network upgrades to the first project that triggers the upgrade.[30] Many times these network upgrades can double the initial estimated interconnection costs, resulting in a previously viable project becoming uneconomic. High costs coupled with uncertainty contribute to once-viable projects needing to withdraw from the queue, triggering restudies and further cost shifting. This has become known as the "cascading withdrawals" problem. Cascading withdrawals and restudies are consistently flagged as the cause of interconnection queue delays.[31] Reducing network upgrade costs for any one customer by allocating those costs among several customers will reduce the number of cascading withdrawals and re-studies caused by those withdrawals. SEIA recommends that the Commission set a minimum distribution factor, for Energy Resource Interconnection Service (ERIS) and Network Resource Integration Service (NRIS) studies, to assess network upgrade costs, to network upgrade costs are just and reasonable.

[29] NOPR P 88.

[30] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 8 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf).

[31] MISO, Informational Report, FERC Order 845 Study Delays, Docket No. ER19-1960, at 8 (Nov. 15, 2021); PJM, Informational Report on Interconnection Study Performance Metrics, Docket No. ER19-1958, at 10 (Aug. 16, 2021).

6. The Commission should ensure that costs allocated between clusters are not significantly impacted by the withdrawal of earlier clustered projects.

SEIA generally supports the proposal to allocate costs between clusters. An inter-cluster cost allocation methodology recognizes that interconnection customers may benefit from earlier-in-time network upgrades. It would be consistent with the Commission's cost-causation principles to require those customers to pay for those benefits.[32] Such an allocation methodology would also alleviate the burden on the earlier-in-time interconnection customer by providing an opportunity to recover some of the network upgrade costs that are likely to benefit later-in-time interconnection customers.

While this proposal accounts for the benefits for a later-in-time interconnection customer, and the appropriate compensation for the earlier-in-time interconnection customer, it does not protect that later-in-time customer from any negative impacts of the actions of the earlier-in-time customer. Specifically, a later-in-time customer may be identified as an entity that benefits from an earlier-identified network upgrade. However, at the time the benefit is identified, it may not be the case that the network upgrade has been *constructed*. Nor would it necessarily be the case that the earlier projects have entered into commercial operation. If the earlier queued projects withdraw from the queue, this could cause the need to reallocate the costs of the network upgrade. Since projects depend on network upgrades from earlier queued resources, projects withdrawals from earlier queued resources may create significant financial burden on later

[32] *See Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043, P 518 (2018), *errata notice*, 167 FERC ¶ 61,123, *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137, P78, *errata notice*, 167 FERC ¶ 61,124, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019) ("The principle of cost causation generally requires that costs 'are to be allocated to those [that] cause the costs to be incurred and reap the resulting benefits.'") (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 87 (D.C. Cir. 2014)) (quoting *NARUC v. FERC*, 475 F.3d at 1285).

queued projects. While the Commission proposes that "to require that the interconnection customer in the later study cluster not be required to pay for its share of the cost of the shared network upgrade until that shared network upgrade is in service,"[33] it is unclear whether it is possible for those network upgrade costs to increase. SEIA requests that the Commission implement protections for later-in-time customers from impacts of earlier queue withdrawals.

7. Increased study deposits can help better identify viable projects.

SEIA generally supports the proposal to increase study deposits and to implement those increased deposits in a tiered manner.[34] The Commission has recognized, both within RTOs and outside of them, that increased study deposits better identify viable projects and reduce the number of multiple interconnection requests made by the same customer for the purpose of evaluating the costs of different project sites.[35] Further, increased study deposits more accurately reflects the costs of the study and recognizes that larger projects likely carry a greater risk.[36]

However, these increased deposits must be paired with reforms to ensure reliable information on transmission capacity. As the Commission stated in the 2008 Order on Technical Conference regarding interconnection queue practices, "the more stringent the requirements, the more important it is to ensure that customers have access to alternative sources of reliable information about available transmission capacity to help them tailor their interconnection requests more narrowly toward a single acceptable interconnection configuration."[37] Without

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[33] NOPR P 99.

[34] NOPR P 106.

[35] *Sw. Power Pool, Inc.*, 178 FERC ¶ 61,015, at P 45 (2022); *Pub. Serv. Co. of New Mexico*, 136 FERC ¶ 61,231, P 80 (2011); *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 16 (2008)

[36] *Pub. Serv. Co. of New Mexico*, 136 FERC ¶ 61,231, P 80 (2011); *see also Sw. Power Pool, Inc.,* 128 FERC ¶ 61,114, P 61 (2011).

[37] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 16 (2008).

reliable information on where there are transmission constraints, developers will be unable to make efficient siting decisions and the incentive to submit multiple exploratory results will still exist.

8. Requiring interconnection customers to demonstrate 100% site control at the time of the interconnection request may be unreasonable.

SEIA generally supports the Commission's proposal to require interconnection customers to demonstrate site control and exclusive land rights over the site.[38] More stringent site control requirements "may help to reduce the number of speculative, duplicative, and non-ready projects."[39] The lack of stringent site control requirements has proven to be an issue in PJM, where projects with inadequate site control were not ready to move forward in the interconnection process.[40] SEIA has consistently supported imposing more stringent site control requirements, because doing so helps to eliminate some speculative projects from the queue.[41]

However, it is not necessarily always possible to acquire 100% site control, especially in instances where the interconnection studies produce results that would require a reconfiguration of a project or other additional site needs. When an interconnection customer enters the queue, there is generally some certainty in the size of facility and the acreage necessary to support that

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[38] NOPR P 116.

[39] *Midcontinent Indep. Sys. Operator, Inc.*, 169 FERC ¶ 61,173, P 45 (2019).

[40] PJM Interconnection Reform Filing, n.144.

[41] Comments of the Solar Energy Industries Association, Docket No. ER22-2110 (July 14, 2022); Joint Supplemental Comments of the American Clean Power Association, Advanced Energy Economy, the Solar Energy Industries Association, and the American Council on Renewable Energy on Generation Interconnection Queue Processing and Cost Allocation Reforms, Docket Nos. AD21-15 and RM21-17 (Feb. 14, 2022); Dave Gahl et al., Lessons from the Front Line: Principles and Recommendations for Large-scale and Distributed Energy Interconnection Reform (June 14, 2022), https://seia.org/sites/default/files/2022-06/SEIA%20Interconnection%20Paper%206-14-22%20FINAL.pdf.

facility.[42] What an interconnection customer generally does not know, though, is the Transmission Provider's Interconnection Facilities for which they will be responsible.[43] This information is not even finalized until after the transmission provider produces the facilities study report.

SEIA recommends setting a site control requirement of 75%, for the generating site only, at the time of the interconnection request to allow for flexibility to interconnection customers to adjust their projects as necessary to address the results of the interconnection studies or other regulatory changes that can affect the size of a project. Further, SEIA requests that the Commission require transmission providers to allow interconnection customers to shift site boundaries or reduce the size of the project, subject to review of any associated changes to collection system or other electrical parameters under the applicable Permissible Technological Advancement or Material Modification review processes, so long as the project does not change its point of interconnection, in order to accommodate any needed changes to the project layout resulting from the interconnection studies or other regulatory changes.

SEIA supports a deposit in lieu of site control requirement.[44] SEIA recognizes that there are certain regulatory limitations when it comes to obtaining site control, especially when a project is sited on public land. It can take projects siting on public lands up to seven years to

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[42] Although, acreage needs are not always certain. For example, in March 2022, the Virginia Department of Environmental Quality issued a memo that would effectively consider solar panels an unconnected impervious surface, which would increase the amount of land necessary for a project to comply with state environmental concerns, and would apply to any project that did not have a stormwater management plan in place. *See* Virginia Department of Environmental Quality, Post-development Stormwater Management at Solar Projects (March 29, 2022), https://www.deq.virginia.gov/home/showpublisheddocument/13985/637842474433400000.

[43] The *pro forma* LGIA defines "Transmission Provider's Interconnection Facilities" as "all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement." Not every region uses this term.

[44] NOPR P 118.

receive permitting and site control. Requiring those projects to obtain full site control before submitting its interconnection request would be burdensome and potentially prohibitive.

9. The commercial readiness requirements are commercially infeasible, impose unnecessary uncertainty in the interconnection process, and raise costs to consumers.

SEIA strongly opposes the proposal to include a commercial readiness framework. The commercial readiness framework proposed in the NOPR is inconsistent with the project development cycle and will impose significantly higher costs on the few companies that could make such showings, increase costs to consumers, and introduce needless uncertainty to interconnection queues.

a. The commercial readiness demonstration options to enter the queue sets a near impossible standard for independent power producers to meet.

The Commission proposes to provide the following options for a project to demonstrate commercial readiness in order to even enter the queue:[45]

- Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years;
- Reasonable evidence that the project has been selected in a resource plan or resource solicitation process by or for a load serving entity, is being developed by a load-serving entity (LSE), or is being developed for purposes of a sale to a commercial, industrial, or other large end-use customer; or
- Provisional LGIA which has been filed at the Commission (executed or unexecuted), which is not suspended and includes a commitment to construct the generating facility.

It is nearly impossible for an independent power producer to demonstrate any of these options.

[45] NOPR P 129

First, an independent power producer cannot enter into a contract for the sale of the resource or any output from the resource before having any reasonable certainty as to what the costs of the network upgrades associated with its request will be. In order to price a contract associated with a resource, whether it is for the sale of the resource or a Power Purchase Agreement (PPA), an independent power producer must know, or at least have reasonable certainty as to what its final costs will be.[46] An interconnection customer does not receive an estimate of those costs until after the transmission provider produces the system impact study report. If independent power producers are forced to enter into these contracts before these costs were certain, then they would need to incorporate that uncertainty into the PPA offer, which would drive up the costs of these contracts, resulting in higher consumer costs. In the event the independent power producer does not reflect the costs of the network upgrades in its PPA price, either the independent power producer or the consumer may attempt to break the contract, which will lead to increased contractual litigation. The third contractual option, a contract for provision of ancillary services, is almost entirely foreclosed to many inverter-based resource developers, as nearly every transmission provider bars inverter-based resources from providing ancillary services, either explicitly[47] or through operating requirements.[48]

The table below shows the development cycle of a typical project, including when the developer begins contract negotiations and procurement. It also shows an estimate of how long

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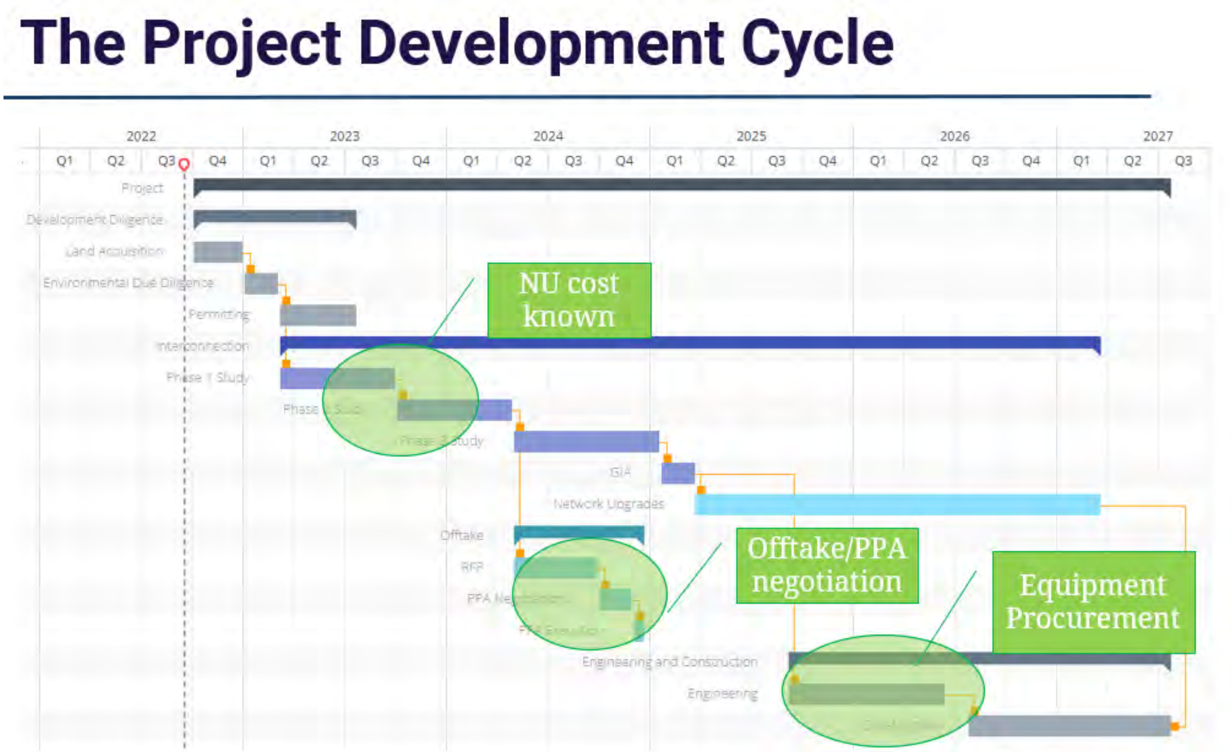
[46] *See* May Joint Task Force Tr. 74:9-21 (Andrew French) ("an essential element of being able to sell a product is to know what your inputs are so you can market it").

[47] *See* MISO Tariff, Section 39.2.1.B ("Resource Requirements for Operating Reserves" ("Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market will be limited to (i) committed Generation Resources that are not Dispatchable Intermittent Resources . . .")).

[48] Fredrich Kahrl, et al., Variable Renewable Energy Participation in U.S. Ancillary Services Markets, at 22-23 (Oct. 2021), https://eta-publications.lbl.gov/sites/default/files/vre_as_full_report_release.pdf.

each contract negotiation may take. Note that this is a "best-case" representation, assuming that the open bid windows for offtake opportunities align well with the interconnection cycle; often, this may not be the case.



Second, requiring an independent power producer to show evidence that the project has been selected in resource plan or other resource solicitation is premature at best. Many state resource plan proceedings require a resource to have made progress through the interconnection process in order to even be considered for the solicitation.[49] Further, this requirement coupled

[49] 2022 EAL Renewables RFP, at 10 (June 14, 2022), https://cdn.entergy-arkansas.com/userfiles/rfp/2022/2022_EAL_Renewables_RFP_Bidders_Conference.pdf?_ga=2.261475407.316220787.1665503441-1210047111.1665503441 (Requiring solar resources looking to participate in the Entergy Arkansas RFP process to have an "executed GIA with MISO or be included in the 2019, 2020 or 2021 MISO DPP Queue."); Dominion Energy Virginia RFP For Development Asset Acquisitions & Power Purchase Agreements Frequently Asked Questions, at 1, https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/renewable-projects/rfp/2022-solar-rfp/bidder-faq-document.pdf?la=en&rev=a81a0db46cd9472c94c9870e1fe72daa&hash=6852077C207CCF784CF7E4B49276F760 ("Our preference is to consider projects that have advanced to the point of having a fully executed PJM System Impact Study Agreement.").

with the proposal to allow Load Serving Entities (LSEs) to request an "Optional Resource Solicitation Study" presents numerous opportunities for a utility to discriminate against independent power producers in favor of that utility's own generation, or amongst independent power producers to favor their preferred counterparty. Under the "Optional Solicitation Study" proposal, an LSE could request an optional resource solicitation study from the transmission provider. As part of that request, the LSE is responsible for identifying the valid interconnection requests associated with the solicitation process. The transmission provider conducts the study, and the LSE can then make integrated resource plan decisions based on that study.[50] Under this paradigm, an LSE will be incentivized to use the study to select generation owned by its associated generation subsidiary, allowing those projects to meet the integrated resource plan demonstration of commercial readiness. In the NOPR, the Commission recognizes this potential for utility self-dealing, especially in non-RTO regions, and uses it as a basis in proposing the deposit in lieu of commercial readiness demonstration.[51] However, as explained below, allowing for the deposit in lieu of commercial to address potentially discriminatory treatment of independent power producers and then subjecting those independent power producers that use that option to higher withdrawal penalties, does not remedy the discriminatory treatment—it compounds that discriminatory treatment.[52]

Even if the project is not part of the solicitation, and is instead being developed for an end-use customer, as with the concern with the PPA pricing, it is nearly impossible for the

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[50] *See* NOPR PP 223-224.

[51] *See* NOPR P 132 ("We note that, outside of RTOs/ISOs, transmission providers may be able to provide certain contractual arrangements to their own projects or other preferred interconnection customers, such as the term sheet option discussed above, which could lead to unduly discriminatory behavior.").

[52] *See* section I.A.9.c. *infra*.

independent power producer to price a sales contract without having reasonable certainty in its final costs. And in RTOs that have capacity auctions, such as PJM, ISO-NE, NYISO, and MISO, requiring a resource to be part of a resource solicitation, or to have a PPA in place, ignores the very nature of a capacity market, which is to allow independent power producers to sell capacity into a market.

Third, the option for an independent power producer to make a showing of commercial readiness with a Provisional LGIA is inconsistent with the independent power producer business model. Independent power producers try to minimize risk in development as much as possible. A Provisional LGIA is inconsistent with that business model, as it would require an independent power producer to assume almost all the risk of the costs of network upgrades without knowing what these costs are.

b. The commercial readiness demonstration options to enter the facilities study are commercially impracticable.

The Commission proposes the following options for a project to demonstrate commercial readiness in order to enter the facilities study:[53]

- Executed contract (as opposed to term sheet), binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years;
- Reasonable evidence that the project has been selected in a resource plan or resource solicitation process by or for a load serving entity, is being developed by an LSE, or is being developed for purposes of a sale to a commercial, industrial, or other large end-use customer; or
- Provisional LGIA accepted for filing by the Commission, which is not suspended, with reasonable evidence that the generating facility and interconnection facilities have commenced design and engineering.

[53] NOPR P 130. We note that if the Commission imposes the commercial readiness requirement proposed in paragraph 129 of the NOPR, there are very few independent power producers that would be able to enter the queue in the first place and reach the facilities study.

Although an independent power producer has some level of cost certainty following the system impact study that precedes the facilities study, requiring an independent power producer to meet any of these commercial readiness demonstrations in order to enter the facilities study would be commercially impracticable.

As stated above, an independent power producer does not have any reasonable certainty as to what its final costs will be until after the transmission provider completes the system impact study report, in which network upgrades are identified. In most regions, there is a relatively short window of time between when the independent power producer receives an estimate of its network upgrade costs in the system impact study report and when it is required to execute a facilities study agreement. In PJM, there are 30 days between receiving the system impact study report and the facilities study execution.[54] In MISO, there are just 15 business days between when the interconnection customer receives the Revised System Impact Study results, which includes cost estimates for upgrades, and Decision Point II.[55] This is not nearly enough time for an independent power provider to negotiate and execute an agreement that generally takes months to complete.

Nor is it reasonable to expect an independent power producer to demonstrate commercial readiness by showing that the project has been selected in a resource plan or resource solicitation

[54] PJM Tariff Sec 206.2 ("For a New Service Request to retain its assigned Queue Position pursuant to Section 201, *within 30 days of issuing the System Impact Study*, the Transmission Provider must be in receipt of (i) all past due amounts of the actual System Impact Study costs exceeding the System Impact Study deposits contained in Section 204.3A, if any, (ii) the executed Facilities Study Agreement and, (iii) the deposit required under this Section 206. If a participating New Service Customer fails to remit past due amounts, execute the Facilities Study Agreement or to pay the deposit required under this Section 206, its New Service Request shall be deemed terminated and withdrawn.") (emphasis added).

[55] MISO Tariff, Attach. X, definition of Interconnection Customer Decision Point II ("Interconnection Customer Decision Point II shall mean the time period beginning when the Interconnection Customer is provided the Revised System Impact Study results including cost estimates for upgrades and the Affected Systems analysis results including cost estimates for upgrades on the Affected System and *concludes after fifteen (15) Business Days*.") (emphasis added).

process. As stated above, many state resource plan proceedings require a resource to have made progress through the interconnection process in order to even be considered for the solicitation.[56] It may not be the case that the windows for the resource solicitation line up with the limited window in which an independent power producer has to execute the facilities study agreement.

Finally, again the option for an independent power producer to make a showing of commercial readiness with a Provisional LGIA is inconsistent with the independent power producer business model. Under a Provisional LGIA, the independent power producer must assume almost all the risk of the costs of network upgrades without knowing their costs. Given the 60-day timeline for the Commission to accept orders under section 205 of the Federal Power Act, an independent power producer must request that a transmission provider execute and file an LGIA with the Commission *before* receiving its network upgrade cost estimates. The independent power producer would be forced to assume unknown costs.

c. The Commercial Readiness Deposit in lieu option is discriminatory towards independent power producers.

The Commission also proposes a framework to allow interconnection customers to provide a commercial readiness deposit in lieu of meeting the commercial readiness requirements.[57] The Commercial Readiness Deposit would be tied to the study deposit amount, with the amount increasing throughout the interconnection process.[58] If an interconnection customer that uses the deposit in lieu option withdraws from the queue, the deposit will be applied toward any withdrawal penalties.[59] These withdrawal penalties are higher for the

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[56] *See* n.49 *supra*.

[57] NOPR P 133.

[58] NOPR P 133.

[59] NOPR P 134.

interconnection customers that made a deposit in lieu of a demonstration of commercial readiness.[60]

The Commission proposes this deposit as a protection against undue discrimination in the interconnection process.[61] However, the proposal for the deposit itself results in undue discrimination against independent power producers. As shown above, it is nearly impossible for an independent power producer to make any of the commercial readiness demonstrations as they are currently proposed in the NOPR. The deposit in lieu of meeting the commercial readiness requirements would not be an "option" for independent power producers: It would be the *only* path forward in the interconnection process.

An independent power producer looking to enter the interconnection process would be forced to agree to pay higher costs, which then increase over the process. These costs are not representative of the cost of the associated network upgrades for the interconnection requests, which would form the basis of any demonstration of commercial readiness. Under this commercial readiness demonstration deposit paradigm, when an independent power producer is weighing the risks of a project, it must be so based on costs that are unrelated to its final costs. While the Commission provides that the deposit would be refundable upon making a demonstration of commercial readiness,[62] in instances of participation in wholesale markets, or even in non-RTO region resource adequacy constructs, it may be the case that an independent power producer never makes one of the proposed commercial readiness demonstrations. Under the proposed rule, as it is currently written, such deposits would not be refunded, and it would

[60] NOPR P 134; NOPR P 144.

[61] NOPR P 132.

[62] NOPR P 134.

increase the costs of the energy and capacity associated with that independent power producer's resource.

The commercial readiness deposit in lieu is an opportunity to discriminate against independent power producers. As the Commission itself recognized, "transmission providers may be able to provide certain contractual arrangements to their own projects or other preferred interconnection customers, such as the term sheet option discussed above, which could lead to unduly discriminatory behavior."[63] A transmission provider or a transmission owner, especially in non-RTO areas, could favor its own projects, and then subject unaffiliated projects to higher costs, making those projects less competitive in the markets or in an IRP proceeding. And the discrimination that the Commission seeks to prevent would remain in the interconnection process.

d. Proposed alternatives to the commercial readiness demonstration.

SEIA proposes that the Commission eliminate the commercial readiness demonstration requirement from the final rule. Making such a demonstration would be nearly impossible for independent power producers, and those that do make that demonstration incur significant contractual risks. Allowing for a Commercial Readiness Deposit is also not a feasible option for independent power producers, as it subjects a class of developers to higher costs and provides an opportunity for undue discrimination. Such a proposal is unjust and unreasonable, and unduly discriminatory, resulting in needlessly higher rates to ratepayers.

If the Commission does not eliminate the commercial readiness demonstration, SEIA urges the Commission to modify the requirement as follows:

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[63] NOPR P 132.

- Make the commercial readiness demonstration a requirement to enter into a generator interconnection agreement. A later-stage commercial readiness demonstration will allow independent power producers to make rational business decisions based on reasonably certain network upgrade costs.
- Allow interconnection customers to make a commercial readiness demonstration by providing an affidavit that it will sell energy, capacity, and/or ancillary services, as a wholesale merchant generator. Not only should this demonstration be available to developers within an RTO, but it should also be available to generators outside of one to allow developers to sell capacity to meet resource adequacy needs.
- Allow interconnection customers to make a commercial readiness demonstration by providing documentation of developer due diligence, including Available Transmission Capacity and modeling.
- Maintain the deposit in lieu of meeting commercial readiness option but set the value of the deposit as a percentage of the estimated network upgrade costs, which should be capped at $2,000,000. Additionally, the withdrawal penalties for interconnection customers that utilize this option should not be any different than the withdrawal penalties other interconnection customers face.

SEIA understands the need to increase the requirements imposed on interconnection customers as a means to reduce the number of non-viable in the queue. However, in setting forth a commercial readiness demonstration requirement that is nearly impossible to meet, the Commission would be incorrectly implying that projects developed by independent power producers are inherently not commercially viable to begin with. Independent power producers play a critical role in bringing robust competition to the markets. They drive innovation and decrease the cost of providing power.[64] "The public interest requires policies that do not harm the development of vibrant, fully competitive generation markets."[65]

10. Excessive withdrawal penalties incentivize non-viable projects to stay in the interconnection queue.

SEIA does not support the Commission's proposal to require transmission providers to assess increasingly higher withdrawal penalties to interconnection customers that withdraw from

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[64] *AmerenUE*, Opinion No. 473, 108 FERC ¶ 61,081, P 61 (2004).

[65] *Id.*, P 59.

the interconnection process.[66] Increasing the amount of money at stake for an interconnection customer, and not providing off-ramps from the interconnection process does not incentivize projects to exit the queue. As a project progresses through the interconnection process, its penalty will be higher. When network upgrades are assessed, it becomes a game of who blinks first: A project may not really be able to afford its share of the network upgrade but knows that if it stays in the queue long enough, other projects will withdraw, and the penalty *those* projects pay will eventually be distributed to the remaining projects in the cluster.[67] Although the proposal exempts interconnection customers from the withdrawal penalty if there is no impact to other generating facilities in the same cluster,[68] it has been SEIA's members' experience that withdrawals almost always impact other generating facilities in the cluster. It is very likely that withdrawal penalties would be unavoidable.

Higher withdrawal penalties will not "encourage interconnection customers to make every effort to ensure their proposed projects are viable."[69] Better project development decisions come from better information, and more transparency into capacity constraints will allow interconnection customers to make siting decisions that will reduce the likelihood of prohibitively high network upgrade costs.[70] Further, as the Commission has recognized "the

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[66] NOPR PP 141-144.

[67] *See* Proposed LGIP Section 3.7.1.2 ("Withdrawal Penalty revenues associated with Section 3.7.1.1(c) of this LGIP shall not be distributed to the remaining Interconnection Customers in that Cluster until all Interconnection Customers in that Cluster have reached Commercial Operation and thereafter shall be distributed as described above.").

[68] NOPR P 141.

[69] NOPR P 140.

[70] *See* Section I.A.2. *supra.*

business of developing generation is very dynamic and requires the coordination of a whole host of factors beyond interconnection, *many of which are outside the full control of the developer*."[71]

A better solution would be for the Commission to direct transmission providers to implement processes like the MISO interconnection and off-ramp process. Under the MISO interconnection process, an interconnection customer makes an initial deposit that is tied to the size of the project.[72] Subsequent milestone payments are then tied to the cost of the network upgrades.[73] Throughout the process, interconnection customers have several decision points, or off-ramps, at which point they risk losing part or all of their escalating deposit amounts and at later phases, a portion of payment for network facilities. While there is still a loss of money for late-stage withdrawals, those amounts would be based on actual upgrade costs.[74] This process creates more certainty for the dollar amounts customers have at risk when they deliberate proceeding through the interconnection process milestones, and they can make better cost-based decisions at those milestone points with regard to taking an off-ramp.

Under a process like MISO's, projects would be incentivized to withdraw from the queue earlier in the process, instead of facing the choice between a steep withdrawal penalty or waiting for other projects to withdraw. Additionally, the Commission should direct transmission providers to implement a process like MISO's pre-DPP Screening Analysis.[75] Under this model, transmission providers would be required to perform an indicative non-binding screening analysis to identify potential thermal and voltage constraints for customers entering the cluster.

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[71] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 14 (2008).

[72] MISO Tariff, Attachment X, 3.3.1.

[73] MISO Tariff, Attachment X, 7.3.1.4.1 and 7.3.2.4.1.

[74] *Midcontinent Indep. Sys. Operator, Inc.*, 158 FERC ¶ 61,003, P 43 (2017).

[75] *See* MISO Tariff, Attachment X, Section 7.1.1.

Following the results of that Screening Analysis, interconnection customers would be able to determine whether they should proceed through the process, or withdraw, penalty-free, before making significant financial investments. This process would provide information necessary to make efficient project viability decisions while also recognizing that, despite a developer's best efforts, there are some factors that affect the development process that are beyond their control.

11. The commercial readiness requirements in the transition proposal will effectively bar many late-stage projects from the transitional study process.

SEIA generally supports the Commission's proposal to implement a transitional serial study.[76] However, SEIA opposes the requirement for the interconnection customer to make a commercial readiness demonstration and the deposit requirement to enter into the transitional serial study.

Under the Commission's proposal, interconnection customers that have executed a facilities study agreement at the time of the transition would have 60 days to provide evidence of exclusive site control for the entire generating facility and demonstrate commercial readiness.[77] To demonstrate commercial readiness, an interconnection customer would need to show:

- an executed term sheet (or comparable evidence) related to a contract for the sale of the generating facility or its energy/ancillary services;
- reasonable evidence that the generating facility is included in a resource planning entity's resource plan, has received a contract via a resource solicitation process, or is being developed for a large end-use customer; or
- a provisional LGIA that is not suspended and includes a commitment to build the generating facility.

[76] NOPR P 158-159.

[77] NOPR P 159.

These would be the same commercial readiness demonstrations an interconnection customer would need to make to enter the queue under the Commission's proposed new rule.[78]

In addition to the commercial readiness demonstration, an interconnection customer would need to provide a deposit equal to 100% of the interconnection facility and network upgrade costs allocated to the interconnection customer in the system impact study report.[79] If the interconnection customer were to withdraw from the transitional cluster, then the withdrawal penalty would be nine times the study cost.[80]

SEIA opposes the commercial readiness demonstration in the transition proposal for the same reasons it opposes the commercial readiness demonstration under a new interconnection process: The demonstration sets a near impossible standard for independent power producers to meet and ignores the very nature of a capacity market, which is to allow independent power producers to sell capacity into a market.

Rather than requiring interconnection customers to make a demonstration of commercial readiness to enter into the transitional study, SEIA recommends that the Commission require interconnection customers to provide a readiness deposit and evidence of site control. In order to protect the projects in the transitional cluster from the effects of withdrawal, the withdrawal penalty should be capped at the withdrawing project's allocation of network upgrade costs.

B. Reforms to increase the speed of Interconnection

Interconnection reform must be a matter of compromise. Interconnection customers, transmission providers, and transmission owners, must each do their part to address the issue.

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[78] *See* NOPR P 129.

[79] NOPR P 158.

[80] NOPR P 158.

Under the current interconnection paradigm, though, only interconnection customers bear the burden of compliance. If an interconnection customer does not meet any of the requirements it faces, it loses its queue position, and much of the investment it made in its project. Meanwhile, if a transmission provider or transmission owner fails to meet a tariff deadline, it does not face any penalties.[81] Processing interconnection requests in a timely manner "is critical to maintaining just and reasonable rates."[82] And yet, as the Commission notes, "nearly all transmission providers across the country regularly fail to meet interconnection study deadlines."[83] The backlog in the interconnection queues that result from these delays cause significant harm. They "not only deprive generation developers of needed business certainty, they also undermine other important public goals."[84] SEIA strongly urges the Commission to enact the reforms proposed in Sections II.B.1 and II.B.2 of the NOPR, which would level the playing field between interconnection customers and transmission providers and ensure a more efficient and equitable interconnection process.

1. Eliminating the "reasonable efforts" standard will incentivize the transmission providers to complete interconnection studies in a reasonable amount of time.

SEIA strongly supports the Commission's proposal to eliminate the reasonable efforts standard for transmission providers completing interconnection studies, and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet these deadlines.[85] Currently, transmission providers are required to use "reasonable efforts" to

[81] NOPR P 166.

[82] NOPR P 167.

[83] NOPR P 166.

[84] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 5 (2008).

[85] NOPR P 168.

meet their tariff defined study deadlines. Order No. 2003 defined "reasonable efforts" as "actions that are timely and consistent with Good Utility Practice and are substantially equivalent to those a Party would use to protect its own interests."[86] Following Order No. 2003, it does not appear that the Commission has ever found delays in the interconnection process that amounted to a violation of the standard.[87]

Transmission providers across the country "regularly fail to meet interconnection study deadlines."[88] The reasons cited for these delays include "the high volume of interconnection requests" and "re-studies caused by withdrawal of higher-queued interconnection requests."[89] This is only part of the story. First, the high volume of interconnection requests is a response by developers to meet federal, state, local, and corporate decarbonization goals. The number of interconnection requests have increased because demand for energy is shifting in response to the climate crisis. As electrification of transportation and buildings increases to meet these goals,[90] the amount of clean energy needed to meet the increase energy demand will need to increase as well. While the transmission system was originally planned to accommodate the operational characteristics of mostly thermal generation resources, clean energy sources have markedly different characteristics and pose different transmission demands. These resources are generally smaller with respect to output and require more of them to meet the same energy demands. This

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[86] Order No. 2003, P 65, 67.

[87] *See, e.g. Hecate Energy Greene County 3 LLC v. Cent. Hudson Gas & Elec. Corp.*, 176 FERC ¶ 61,023, at P 44 n.103 (2021); *EDF Renewable Energy, Inc. v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,071, at P 12 (2018); *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,050, at P 45 (2013).

[88] NOPR P 166.

[89] NOPR P 165, nn. 239-240.

[90] *See e.g.* Fiona Wissell, Brittany Speetles, Matt Townley, Deb Harris, and Stacy Noblet, The Impact of Electric Vehicles on Climate Change, at 4-5, https://www.icf.com/insights/energy/impact-electric-vehicles-climate-change (showing that electric vehicle sales doubled between 2020 and 2021).

has resulted in more interconnection requests needed to meet the same amount of energy demanded. Allowing backlogs to continue will undermine "important public goals."[91] It is incumbent on transmission providers to take concrete steps to improve the timeliness and accuracy of its interconnection studies in order to help meet these critical public goals.[92]

The other part to the interconnection delay story is that interconnection withdrawals and subsequent restudies are two problems caught in a vicious negative feedback loop. Queues across the country have been backlogged for some time, and with more incentives for clean energy resources to enter the market, the backlogs will continue. The backlogs "deprive generation developers of needed business certainty" and with more business uncertainty, projects face issues such as losing site control rights and financing, which would make once-viable projects no longer so.[93] Withdrawals have become the natural consequence of backlogs, which themselves leads to further withdrawals.

Restudies triggered by project withdrawals could be mitigated by the reforms proposed by the Commission in this proceeding. Providing more upfront information to interconnection customers will allow them to make efficient siting decisions and reduce the need to submit exploratory interconnection requests.[94] Moving to a cluster study approach will lessen the financial burden of those upgrades on any one interconnection customer, which should lead to

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[91] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 5 (2008).

[92] *See Southwest Power Pool, Inc.*, 178 FERC ¶ 61,015, P 49 (2022) ("With regard to commenters' concerns about SPP lacking the resources and staffing necessary to implement its proposal, we expect SPP to continue to take concrete steps to improve the timeliness and accuracy of its interconnection studies. Such steps are particularly critical in light of recent errors and missteps in SPP's implementation of its study process. We note SPP's commitments to significantly increase its budget for outside consultants, hire and retain staff, enhance its modeling methodology, and work with transmission owners to ensure study deadlines are met. We expect SPP to fulfill these commitments, all of which appear to be both critical and necessary for SPP to mitigate its extensive backlog. We further expect that SPP will devote all necessary resources to its backlog mitigation effort.").

[93] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 5 (2008).

[94] *See* Section I.A.2 *infra*.

fewer project withdrawals.[95] And if the Commission amends its proposal on withdrawal penalties,[96] projects will be incentivized to exit the queue earlier in the process, reducing the impact on the remaining projects in the queue. However, these reforms will not completely resolve interconnection backlogs, and without an incentive for transmission providers to fulfill their requirements to complete the interconnection studies on time, there is no guarantee that the reforms will be effective. The lax definition of reasonable efforts in effect right now does not incentivize transmission providers to devote sufficient resources to completing accurate interconnection studies on time.[97] Removing the reasonable efforts standard, and imposing consequences for transmission providers that do not meet tariff deadlines, will help bring certainty to the interconnection process, turning the vicious circle of delays, withdrawals, and further delays into a virtuous one, in which projects have certainty in timelines and financing, leading to more finalized projects.

To the extent that transmission providers lack the resources to complete the studies, the Commission should make clear in the final rule that interconnection customers can use third-party consultants to produce required studies in accordance with transmission provider standards and criteria. Allowing interconnection customers to use third-party consultants will conserve transmission provider resources and provide a path forward through the process for interconnection customers.

Transmission provider delays are just part of the problem, though. Transmission owners are also responsible for completing parts of the interconnection studies. The Commission's

[95] *See* Section I.A.4 *infra*.

[96] *See* Section I.A.10 *infra*.

[97] Transcript 63:17-20 (Clements), Docket No. AD21-15 (May 6, 2022); Transcript 73:12-17 (Glick), Docket No. AD21-15 (May 6, 2022).

proposed rule, as written, only imposes the requirement on the transmission provider. SEIA requests that the Commission ensure that transmission owners are also financially responsible for these delays by either: (1) allowing transmission providers to recover the costs of transmission owner delays from the transmission owner; or (2) directly impose fines on the transmission owner. In order to protect consumers, transmission owners must not be allowed to recover those costs through their rates. Further, SEIA recommends that the Commission set the fine at $500 per day *per customer* and remove the cap on penalties.[98] Higher penalties are not punitive—they are compensatory. Delays in the interconnection process have significant impacts on interconnection customers as well as end-use customers. Higher penalties reflect the damage delays cause to all stakeholders.

2. Implementing an Affected System Study Process, along with *pro forma* Affected System Agreements and standardized study assumptions, will alleviate a significant barrier to an efficient interconnection process.

SEIA supports the proposal to standardize the Affected System Study process and implement a *pro forma* Affected Systems Study Agreement.[99] The Affected System process is a major barrier to interconnection. Although each region has an obligation to consider Affected Systems in its generator interconnection studies when it is the host region and to undertake Affected System analysis as the neighboring region,[100] there is no documented process for how the Affected Systems coordination occurs. The lack of transparency and certainty in this process has resulted in significant harm to interconnection customers, as their ability to make decisions

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[98] *See* NOPR P 170.

[99] NOPR PP 183, 197.

[100] Order No. 2003, P 118.

regarding entering or remaining in the interconnection queue is impacted by the uncertainty in the Affected System process.[101] Standardizing the process and providing more information to interconnection customers about the relative impacts of their projects, would provide greater certainty. Requiring firm deadlines and penalties associated with that process would enforce that certainty.

SEIA further supports the Commission's proposal to allocate network upgrade costs using a proportional impact method,[102] for the same reason we support the Commission's proposal to allocate intra-cluster network upgrade costs: High costs coupled with uncertainty contribute to once-viable projects needing to withdraw from the queue, triggering restudies and further shifting costs—better known as the "cascading withdrawals" problem. Cascading withdrawals and restudies have been consistently flagged as the cause of interconnection queue delays.[103] Reducing network upgrade costs for any one customer by allocating those costs among several customers will reduce the number of cascading withdrawals and re-studies caused by those withdrawals. SEIA recommends that the Commission set a minimum distribution factor for ERIS and NRIS studies to assess network upgrade costs, to provide equity across seams and ensure that affected systems network upgrade costs are just and reasonable.

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[101] *EDF Renewable Energy, Inc. v. Midcontinent Independent System Operator, Inc.*, 168 FERC ¶ 61,173, P 20 (2019).

[102] NOPR P 189.

[103] MISO, Informational Report, FERC Order 845 Study Delays, Docket No. ER19-1960, at 8 (Nov. 15, 2021); PJM, Informational Report on Interconnection Study Performance Metrics, Docket No. ER19-1958, at 10 (Aug. 16, 2021).

3. The Optional Resource Solicitation Study will provide opportunities to discriminate against independent power producers.

SEIA strongly opposes the Commission's proposal to require transmission providers to allow a resource planning entity to initiate an optional resource solicitation study. An optional resource solicitation study in situations where there is a commercial readiness requirement presents numerous opportunities for a utility to discriminate against independent power producers in favor of that utility's own generation. Under the "Optional Solicitation Study" proposal, an LSE could request an optional resource solicitation study from the transmission provider. As part of that request, the LSE is responsible for identifying the valid interconnection requests associated with the solicitation process. The transmission provider conducts the study, and the LSE can then make integrated resource plan decisions based on that study.[104] Under this paradigm, an LSE will be incentivized to use the study to select generation owned by its associated generation subsidiary, allowing those projects to meet the integrated resource plan demonstration of commercial readiness. The Commission recognizes this exact outcome, stating that the study helps "interconnection customers receive evidence of selection in a resource plan in a more timely manner by providing the resource planning entity with needed information."[105]

Further, as stated above, transmission providers have consistently stated that they have limited staff resources.[106] Instituting an additional study, especially one that can lead to discrimination against a class of developers, will put another strain on those limited staff resources.

[104] *See* NOPR PP 223-224.

[105] NOPR P 225.

[106] Comments of the Midcontinent Independent System Operator, Inc., at 15, Docket No. RM21-17 (Aug. 17, 2022) (noting that "limited staff resources" may hinder compliance with a new transmission planning rule); Initial Comments of PJM Interconnection, L.L.C. at 12829, Docket No. RM21-17 (Aug. 17, 2022) (explaining how PJM is in the process of expanding its staff in order to address long-term planning).

C. Reforms to incorporate technological advancements into the interconnection process

1. The proposed reforms to increase the flexibility in the interconnection process will allow developers to add complementary generation resources to existing projects, which will provide capacity and reliability to the grid.

The Commission proposes four reforms that would allow interconnection customers to add complementary generation resources to existing interconnection requests or projects already in service. SEIA supports each of these proposals. First, the Commission proposes to require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request.[107] Second, the Commission proposes to require transmission providers to evaluate the proposed addition of a generating facility to an interconnection request as long as the interconnection customer does not request a change to the originally requested interconnection service level, without automatically considering the request to be a material modification.[108] Third, the Commission proposes to require transmission providers to allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an LGIA in place.[109] Finally, the Commission proposes to require transmission providers to use operating assumptions for interconnection studies that reflect the proposed operation of the resource.[110]

Allowing multiple resources to co-locate behind a single point of interconnection while sharing a single interconnection request will allow for significant efficiencies through the interconnection process. It would reduce the number of interconnection requests, by allowing

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[107] NOPR P 242.

[108] NOPR P 255.

[109] NOPR P 264.

[110] NOPR P 280.

two, co-located resources, to be studied as a single request.[111] These studies would also be more accurate, as they would reflect the actual electrical impact when connected to the transmission system.[112] SEIA requests clarification on the terminology used in this proposal. In January 2021, in its order directing reports on information related to hybrid resources, the Commission used two distinct terms to identify hybrid resource market participation. "Co-located hybrid resources" are defined as two separate resources sharing a single point of interconnection that are modeled and dispatched separately.[113] "Integrated hybrid resources" are defined as sets of resources that share a single point of interconnection and are modeled and dispatched as a single resource.[114] There are benefits to each model of participation. Interconnection customers can best weigh the advantages and disadvantages of an integrated hybrid resource versus a co-located hybrid resource. As such, SEIA requests that the Commission adopt these terms in its final rule and clarify that interconnection customers retain the choice of how to structure their interconnection requests to best suit their needs and the needs of their customers.

Amending the material modification process to create a rebuttable presumption that the addition of storage to an existing interconnection request is not a material modification will add certainty to the current material modification process. The pro forma LGIA defines material modifications as "those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date."[115] Yet, in several RTOs, adding storage to an existing interconnection request may result in a project losing its valuable queue

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[111] NOPR P 244.

[112] NOPR P 244.

[113] *Hybrid Resources*, 174 FERC ¶ 61,034, P 4 (2021).

[114] *Id*.

[115] *Pro forma* LGIP Art. 1.

position.[116] Adding a second resource without increasing the interconnection service level should not increase the costs to later interconnection requests, as it generally would not require additional network upgrades to accommodate the resource. Nor should the request delay later queued projects, as there would be no additional service to be studied. To the extent that transmission providers require specific types of control technologies to add an additional resource, they should make this transparent. The addition of storage results in better electrical performance. It increases reliability. It improves frequency response. There is no reason to deem such a change to be a material modification, especially when it is in the grid's best interest to add more storage.

Allowing interconnection customers to use the surplus interconnection process to add storage resources can provide significant benefits to the grid quickly, and with a high degree of control and transparency. As the Commission found in Order No. 845, the use of surplus service can:

> reduce costs for interconnection customers by increasing the utilization of existing interconnection facilities and network upgrades rather than requiring new ones, improve wholesale market competition by enabling more entities to compete through the more efficient use of surplus existing interconnection capacity, and remove economic barriers to the development of complementary technologies such as electric storage resources.[117]

Leaving storage resources to languish in backed-up interconnection queues, and denying customers of the benefits these resources provide, will ultimately hurt the markets and hinder grid reliability.

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[116] Rob Gramlich, Michael Goggin, and Jason Berwen, "Enabling Versatility: Allowing Hybrid Resources to Deliver Their Full Value to Customers," *available at* https://gridprogress.files.wordpress.com/2019/09/enabling-versatility-allowing-hybrid-resources-to-deliver-their-full-value-to-customers.pdf (Sept. 2019), at 12.

[117] Order No. 845, P 467.

Finally, requiring transmission providers to use study assumptions that reflect the proposed operation of an electric storage resource will result in just and reasonable rates for interconnection customers and consumers. Assuming that a storage resource will charge from the grid during peak periods improperly treats storage as a load during the highest peak periods, unnecessarily increases interconnection and upgrade costs. If the interconnection customer agrees to implement the necessary controls to avoid such charging during peak periods, then the transmission provider should take that into account when determining interconnection and upgrade costs.

2. Evaluating alternative transmission solutions during the cluster study will reduce network upgrade costs.

SEIA supports the Commission's proposal to require transmission providers, upon request of the interconnection customer, to evaluate alternative transmission solutions.[118] Many commenters in the ANOPR proceeding noted how alternative transmission solutions bring improvements in efficiency, capacity, reliability, and resiliency to the system, as well as increases efficient use of the system.[119] Alternative transmission technologies are and ideal medium-term solution to transmission building that bridges the gap in timing between building generation (around five years) and building transmission (around 10 years) by expanding capacity on existing transmission lines enough to allow new generation to come online without significant network upgrades. Decreasing the costs of network upgrades will reduce the number of withdrawals from the interconnection queues, creating a more stable and efficient interconnection process. Decreasing these costs will also reduce the project costs for developers,

[118] NOPR P 297.

[119] *See* NOPR P 290.

who are then able to reflect those savings in power purchase agreements or integrated resource plan submissions.

SEIA generally supports the proposal to require transmission providers to provide information detailing how advanced technologies were considered in interconnection requests.[120] SEIA requests that the Commission provide flexibility to transmission providers in how to provide this information, whether it be in a report to the Commission or regular postings to its OASIS page.

3. Requiring interconnection customers to provide validated models when they submit their interconnection requests is premature and will not result in useful modeling data for the transmission provider.

SEIA opposes the Commission's proposal to require interconnection customers with non-synchronous resources to submit a generic library RMS positive sequence dynamics model, including a model block diagram of the inverter control system and plant control system, and a validated EMT model, if the transmission provider performs an EMT study as part of the interconnection study process.[121] Providing such models with the interconnection request is overly burdensome to interconnection customers and does not produce useful modeling data for transmission providers.

As an initial matter, some of these models are difficult to provide. Currently in the US, EMT models are not yet industry standard models. There is a limited talent pool of engineers that are able to conduct the studies. EMT models also require significant processing power compared

[120] NOPR P 302.

[121] NOPR P 329.

to RMS models.[122] An EMT model is not necessarily more accurate either. Different models have different uses and no one model fits all situations.[123]

What matters in modeling are the parameters used in each model. Requiring interconnection customers to use generic models, rather than user-defined models, could fail to identify the reliability impacts of a specific plant.[124]

Providing these studies at the interconnection request phase will not provide useful information as there are changes in inverters, network upgrades, and assumptions between when the request is submitted and when the project comes online. Even if there are no changes to the model between the interconnection request and commercial operation of the resource, there is no guarantee that the information in the interconnection customer produced models will be correct, as they rely on grid system information from the transmission providers. There is no corresponding requirement in this NOPR that would obligate the transmission provider to share that information.

SEIA requests that the Commission modify this requirement as follows:

- Require interconnection customers to provide all operating models within one year before the commercial operation date of the resource, in order to reflect the most accurate operating information in the models.
- Require transmission providers to make available to interconnection customers the necessary system data needed to create the models, to ensure that the models more accurately represent system operation.
- Require transmission providers to provide clear modeling requirements and validation guidelines and procedure.[125] If there is a need to change the modeling

[122] Summary of the Joint Generator Interconnection Workshop, 28 (Aug. 9-11, 2022), https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf ("Generator Interconnection Workshop Summary").

[123] *Id*. at 23.

[124] *Id.* at 24.

[125] *See e.g.* California ISO, Electromagnetic Transient Modeling Requirements (April 14, 2021), http://www.caiso.com/Documents/CaliforniaISOElectromagneticTransientModelingRequirements.pdf.

requirements, then transmission providers should engage stakeholders before making such changes.

- Allow interconnection customers to use user-defined RMS models, which will better reflect the actual technology used by the resource.

4. The Commission should use IEEE 2800 and 1547 as the ride-through standard reference.

SEIA requests that the Commission amend its proposal to modify article 9.7.3 of the *pro forma* LGIA and article 1.5.7 of the *pro forma* SGIA, so that the reference standard is IEEE 2800 or successor standards for large generators and IEEE 1547 for small generators.[126] Inverter-based resources are currently capable of providing ride-through. Many inverter-based resources have implemented such controls following the release of the consensus-based standards.

The IEEE 2800 standard establishes the required interconnection capability and performance criteria for inverter-based resources interconnected with transmission and sub-transmission systems for reliable integration into the bulk power system, including:

> voltage and frequency ride-through, active and reactive power control, dynamic active power support under abnormal frequency conditions, dynamic voltage support under abnormal voltage conditions, power quality, negative sequence current injection, and system protection.[127]

IEEE 2800 was developed by 175 industry experts over two years and was approved in April 2022 with a 94% approval rate.[128] The goal of the standard is to have harmonized interconnection requirements across different regions and jurisdictions.[129] The standard is still voluntary though. Incorporation into the LGIA would make it mandatory. And in making this standard mandatory, the Commission would bring some certainty in project design, as the

[126] Generator Interconnection Workshop Summary at 20.

[127] IEEE 2800-2022, https://standards.ieee.org/ieee/2800/10453/.

[128] Generator Interconnection Workshop Summary at 32.

[129] *Id*.

reliability requirements for each project would be known at the time of the interconnection request.[130]

SEIA recommends that the Commission amend the proposed revisions to LGIP Article 9.7.3 to remove the following:

> *Interconnection Customer shall also implement under-voltage and over-voltage relay set points, or equivalent electronic controls, to ensure voltage "ride through" capability of the Transmission System.*

The language should be replaced with the following:

> *Interconnection Customer shall also implement the capability and performance criteria for inverter-based resources set forth for inverter-based resources in IEEE standard 2800, or any successor standard.*

II. CONCLUSIONS

Interconnection reforms alone will not resolve the issues plaguing interconnection queues across the country. In its 2008 Order on Technical Conference, the Commission stated that it believed that "the improved transmission planning required under Order No. 890 will address some of the causes of the current interconnection queue problems."[131] But improved transmission planning has not resulted in new transmission being built.[132] Without new transmission capacity for new resources,[133] the reforms in this NOPR will serve merely as a Band-Aid to a broken interconnection process. SEIA urges the Commission to issue a final rule in this proceeding, as well as the in transmission planning proceeding in Docket No. RM21-17,

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[130] *Id.* at 18.

[131] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 8 (2008).

[132] *See* Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 21 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.) ("The total regionally planned transmission investment in [regional transmission organizations] decreased by 50 percent.").

[133] *See Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 15 (2008).

to resolve the full scope of issue facing the interconnection and transmission planning processes and ensure that the grid is prepared for the changes we must make in response to the climate emergency.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of this pleading has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 13th day of October 2022.

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief.	)))))	Docket No. U-21193 Administrative Law Judge Sharon Feldman

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Testimony of Kelsey Bilsback, Boratha Tan, and Kevin Lucas on Behalf of The Environmental Law & Policy Center, The Ecology Center, Union of Concerned Scientists and Vote Solar* was served by electronic mail upon the following Parties of Record, Thursday, March 9, 2023.

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