UNITED STATES OF AMERICA
BEFORE THE
U.S. ENVIRONMENTAL PROTECTION AGENCY

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule	)))))	**EPA-HQ-OAR-2023-0072-0001**

COMMENTS OF ISO NEW ENGLAND INC.

ISO New England Inc. (ISO) appreciates the opportunity to comment on the Environmental Protection Agency's (EPA) proposed Clean Air Act Section 111 regulation on greenhouse gas emissions from fossil fuel power plants. The ISO respectfully provides general comments on the proposed rule, a description of the analysis it conducted to assess the effects of the proposed rule in New England, the results of that analysis, and recommendations for EPA's consideration as it develops a final rule.

The ISO has reviewed the proposed regulation, and given the limited time for analysis, was only able to conduct a high-level assessment of the rules' impact on regional generation, emissions and wholesale electricity costs. The ISO is aware that EPA plans to publish a separate rulemaking so as to cover all of the existing natural gas fleet. It is important to note that, until all parts of the rule are published, it is difficult for the ISO to gauge the overall impact of this current proposed rule and the results of this analysis may be underestimating the impact of the rule on future grid reliability.

The results of the ISO's analysis indicate that, under the proposed regulation, the impact on oil and natural gas boilers are minimal, and the most impacted resources are natural gas combine cycle (NGCC) electrical generating units (EGUs). Since this proposed rule only regulates large NGCC greater than 300 MW operating at greater than 50% capacity factor, the resulting effect is a shift in generation from these large EGUs to the smaller, less efficient EGUs. Furthermore, if the EPA were to lower the nameplate capacity and capacity factor thresholds, by the ISO's calculation, this could result in a net increase of emissions of up to 3.63% or 0.75 million tons of CO_2 annually. On the energy market side, the effect of enforcing these capacity factor thresholds could cause the following scenarios:

- Generators with capacity factors near 50% could have a strong incentive to avoid the energy market if compliance costs exceed potential energy profits.
- Generators operating far from the 50% capacity factor thresholds would have weaker incentives, which would cause market imbalances.

Another concerning trend shown by the ISO's analysis is that, with all coal EGUs assumed to retire by 2032 and less generation from the regulated larger NGCC EGUs, the model tends to dispatch more expensive dispatchable EGUs, such as active demand response (ADR), at $1,500/MWh. These resources actively curtail voluntary customer load during specific times. While the model excessively dispatches ADR to fill in the gap, this amount of ADR would not be feasible in the real world. Realistically, additional resources may need to be added for reliability or operating actions would have to be relied upon more frequently. Such operating actions could include voltage reductions, energy conservation, and reliance on emergency assistance from neighboring regions. If ADR resources dispatch as often as they are in the results of the ISO's analysis (a large increase from today) some resources may no longer choose to provide ADR. In the absence of ADR, other load in this model would go unserved.

If EPA's objective is to reduce emissions and promote highly efficient generation, then these emission guidelines may be counterproductive. Restricting the large, more efficient NGCC will likely not reduce fossil fuel generation; rather, it will shift generation to less efficient higher emitting fossil fuel generation. If the subsequent rulemaking further restricts the remaining natural gas fleet, there will likely be unserved energy in New England, which could lead to the more frequent use of operating actions, possibly leading to load shedding. It is difficult to know the extent of the impact without the second part of this rule pertaining to the smaller NGCC EGUs.

As EPA continues to develop its proposed rules, the ISO respectfully requests that the EPA coordinate technical conferences with Independent System Operators/Regional Transmission Organizations (RTOs) and FERC to address reliability concerns specifically pertaining to these proposed emission guidelines. This coordination can further support the EPA's and Department of Energy's efforts to support grid reliability and engage in regular outreach with the Federal Energy Regulatory Commission (FERC), as stated in the Joint Memorandum of Understanding on Interagency Communication and Consultation on Electric Reliability.[1]

I. IDENTIFICATION OF THE FILING PARTY

The ISO is the private, not-for-profit entity that serves as the RTO for New England (the region includes Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont). The ISO plans and operates the New England bulk power system and administers New England's organized wholesale electricity markets. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power

[1] "Joint Memorandum on Interagency Communication and Consultation on Electric Reliability," EPA, accessed August 2023.

coordinating Council and the North American Electric Reliability Corporation. FERC regulates the ISO.

II. BACKGROUND

Since 2000, the New England power system has undergone a major transformation – the region has shifted from coal and oil to natural gas-fired generation. Nearly half of the region's electric generating capacity uses natural gas as its primary fuel (about 15,000 MW in 2022), and natural-gas-fired power plants produce about half of the grid electricity consumed in a year (about 54,000 GWh in 2022). In 2022, renewable resources made up 12% of total generation. About 97% of resources currently proposed for the region are grid-scale wind, solar, and battery projects. The region's shift in fuel from coal and oil to less-emitting sources, primarily natural gas, has resulted in significant reductions in emissions from the region's electricity generating fleet. From 2010 to 2021, annual emissions for nitrogen oxides (NOx), sulfur dioxide (SO2), and carbon dioxide (CO_2) declined by, respectively, 57%, 97%, and 36%. While the shift in the resource mix has brought benefits to the region, it has also brought challenges.

Over the past several winters, when renewable resources were unavailable and natural gas supply to electric generation is limited, the New England energy system has relied on oil and coal to produce the electricity the region needs. As more thermal generation facilities that store fuel on-site retire, New England's dependence on an already constrained natural gas system will increase. The proposed rule could make these challenges more acute because it could limit production from, or accelerate the retirement of, non-gas generation (oil and coal).

III. GENERAL COMMENTS ON THE PROPOSED RULE

EPA's proposed rule includes new source performance standards and emission guidelines for CO_2 from the following sources:

- Existing fossil fuel-fired steam generating EGUs (existing coal, oil, and natural gas units).
- Existing fossil fuel-fired stationary combustion turbines EGUs (primarily natural gas units) greater than 300 MW nameplate capacity and capacity factor of greater than 50%.
- New and reconstructed fossil fuel-fired stationary combustion turbines EGUs (primarily new natural gas units).

Individual states would apply EPA's degree of emission limitation to a baseline emission rate for each affected EGU. The baseline is defined as the lb-CO_2/MWh-gross from any continuous 8-quarter period within the 5 years immediately prior to the date the final rule is published in the Federal Register.

As currently written, the proposed new source performance standards and emission guidelines are based on a level of emission reduction that can be achieved through carbon capture and sequestration/storage (CCS) as well as co-firing with low-GHG hydrogen. However, the ISO sees technical and economic hurdles to achieving a successful rollout of these specific technologies in the proposed compliance timeline. The technologies specified in the proposed rule may not be viable options in New England. New England does not have the geological storage capacity to store the amount of CO_2 required.[2] This means most of the captured CO_2 in New England would need to be transported long distances to the Central United States via pipelines. No such infrastructure currently exists.

The lack of geological storage sites in New England also makes it infeasible to implement low-GHG hydrogen co-firing at large scale. Salt caverns are the most viable storage

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[2] "National Assessment of Geologic Carbon Dioxide Storage Resources –Summary," USGS, accessed July 2023.

resources for pure hydrogen, but make up a fraction of the total storage potential in the nation. Assuming that 8.4% of annual demand needs to be stored, similar to current gas storage use, co-firing 96% hydrogen would require 430% of the nation's existing salt cavern storage potential.[3] None of the existing salt caverns is located in New England and hydrogen would need to transport into the region. Currently, there is no existing pipeline infrastructure to transport hydrogen. Natural gas pipelines would need to convert to be able to transport hydrogen.

In the ISO's initial analysis, to be conservative in our assessment of grid reliability, the ISO's model assumes that all coal EGUs will retire and natural gas and oil EGUs will operate below the EPA's capacity factor threshold rather than adopting CCS or low-GHG hydrogen.

IV. ISO ANALYSIS OF THE IMPACT OF THE PROPOSED RULE IN NEW ENGLAND

A. Analysis Description

To benchmark the effect of the EPA's proposed rule, the ISO performed a production cost analysis with and without the EPA's potential rule enforced for the 2032 timeframe. The goal of the ISO's analysis is to quantify the potential effects that the proposed rule may have on reliability and CO_2 emissions to the New England power system as well as the impacts on the fleet of generators both regulated and unregulated by the proposed rule.

The analysis was performed using Energy Exemplar's PLEXOS as a production cost simulation tool. The ISO chose to use the existing Market Efficiency Needs Scenario model developed as part of the Economic Planning for a Clean Energy Transition (EPCET) Study,[4]

[3] "EPRI Cross-Sector Webcast on EPA Power Plant Rules," EPRI, accessed July 2023.

[4] The Economic Planning for a Clean Energy Transition (EPCET) Study is a research and development effort that will help inform future study work and the next steps of the Economic Study Process Improvements. The overall goal of the EPCET study is to prepare the ISO's models, tools, and processes

which is currently underway.[5] This model assumes significant increases to vehicle and heating electrification, base load, and behind-the-meter solar additions in accordance to the ISO's 2022 Capacity, Energy, Load, and Transmission (CELT) report.[6] Additionally, a significant increase in utility scale solar, onshore wind, and offshore wind is assumed as well as retirements to capacity resources resulting from the ISO's sixteenth Forward Capacity Auction and renewable resources procured by each state.

Rather than model the existing generators with the EPA's proposed best system of emission reduction (BSER) additions/ refurbishments, the ISO quantified the effect that the proposed rule would have if generators were to operate in their current state under the EPA's guideline. Due to modeling constraints, the ISO had to simplify its interpretation of the rules to fit within the capabilities of the modeling tool.

Table 1 describes how the ISO modeled generators under specific categories as interpreted under the EPA's proposed rule.

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such that informative and actionable results can be more readily produced in future Economic Study cycles. The ongoing study began in January of 2022 and is expected to conclude by the end of 2023.

[5] *See* https://www.iso-ne.com/committees/planning/planning-advisory/?open_projects_value=Economic%20Planning%20for%20the%20Clean%20Energy%20Transition%20(EPCET)

[6] The ISO's annual 10-year forecast of capacity, energy, loads, and transmission (CELT) is a source for planning and reliability study assumptions. "ISO New England 2022 CELT Report" (August 2022).

Existing EGU Subcategory	Action Taken	Effected Generation (MW) Using ISO Nameplate Capacity	Effected Generation (MW) Using EPA Nameplate Capacity
Coal	Retired	548	548
Existing natural gas (stationary combustion turbines) >300 MW	Max 50% Annual Capacity Factor	8,687	2,911
Existing natural gas and oil (boilers) 1,300 lbs-CO_2/MWh	Max 45% Annual Capacity Factor	0	0
Existing natural gas and oil (boilers) 1,500 lbs-CO_2/MWh	Max 8% Annual Capacity Factor	2,862	2,862

Table 1. Implementation of EPA's Proposed Rule within Production Cost Model

Most coal EGUs will be 60 to 70 years old in 2032. This fact, combined with unknown cost of retrofitting existing coal EGUs to be compliant with the EPA's proposed rule is the reason why coal units were assumed retired in the analysis when the EPA's proposed rule is enforced.

For existing natural gas stationary combustion turbines >300 MW, a 50% capacity factor was enforced. Because the proposed rule does not specify which database or source to refer to for "nameplate capacity," the ISO assumed that nameplate capacity was defined as capacity found in the ISO's 2022 CELT report. As shown in Table 1, if historical heat input based nameplate capacity and capacity factors derived from EPA Clean Air Markets Program Data were used, the amount of affected generation in this category would fall to 2,911 MW. This wide gap between ISO nameplate values and EPA-based historically derived values leads to a large gap in the analysis that could greatly affect the outcome of the EPA's proposed rule. To be conservative and measure the largest effects on the EPA's proposed rule on reliability, the ISO ultimately chose to use the nameplate values from its 2022 CELT report.

For existing natural gas and oil boilers, the ISO derived a list of EGUs that met the 1,300 lbs-CO_2 per MWh and 1,500 lbs-CO_2 per MWh respectively and ran the models with and without constraints on those EGUs outlined in Table 1. After that initial run, any EGUs within this class whose emissions rates exceed the two thresholds were then modeled in accordance to the rules outlined in Table 1 in a secondary run. The effects of these thresholds lead to nearly every oil boiler EGUs being modeled with an 8% annual capacity factor limit.

EPA has requested comment on varying nameplate thresholds and capacity factor limits on stationary combustion turbines. To analyze this, the ISO ran simulations enforcing both 40% and 50% capacity factor limits on stationary combustion turbines at >300 MW, >200 MW, and >100 MW. While EGUs >300 MW affected 8,687 MW of EGUs, >200 MW affected a total of 13,549 MW and >100 MW a total of 14,717 MW.

B. Analysis Results

Preliminary results of the ISO's analysis show that proposed EPA rules would largely pass the generation burden from natural gas stationary combustion turbines >300 MW to smaller, less efficient, natural gas EGUs. This, in turn, would result in a slight decrease of emissions totaling 0.25% or 53 thousand tons of CO_2 annually. Natural gas and oil boilers were already operating below the EPA capacity factor limits so implantation of these limits did not impact them or their emissions. Since enforcing the EPA rule led to increased fuel consumption, the cost of generation (known as production cost) increased by 4.2% from $1.687 billion to $1.758 billion. Of particular concern was the increase in active demand response (ADR) from 4 GWh annually to 37 GWh. ADR is the last dispatchable form of generation within the model and dispatches at $1,500/MWh. The dispatch of ADR occurs primarily in the early hours of the day during the spring on low wind days to help address the issue of ramping due to high penetrations of solar photovoltaic resources during this time of year. Seeing ADR dispatch more frequently when the EPA rules are simulated is indicative of a system that is running out of dispatchable resources.

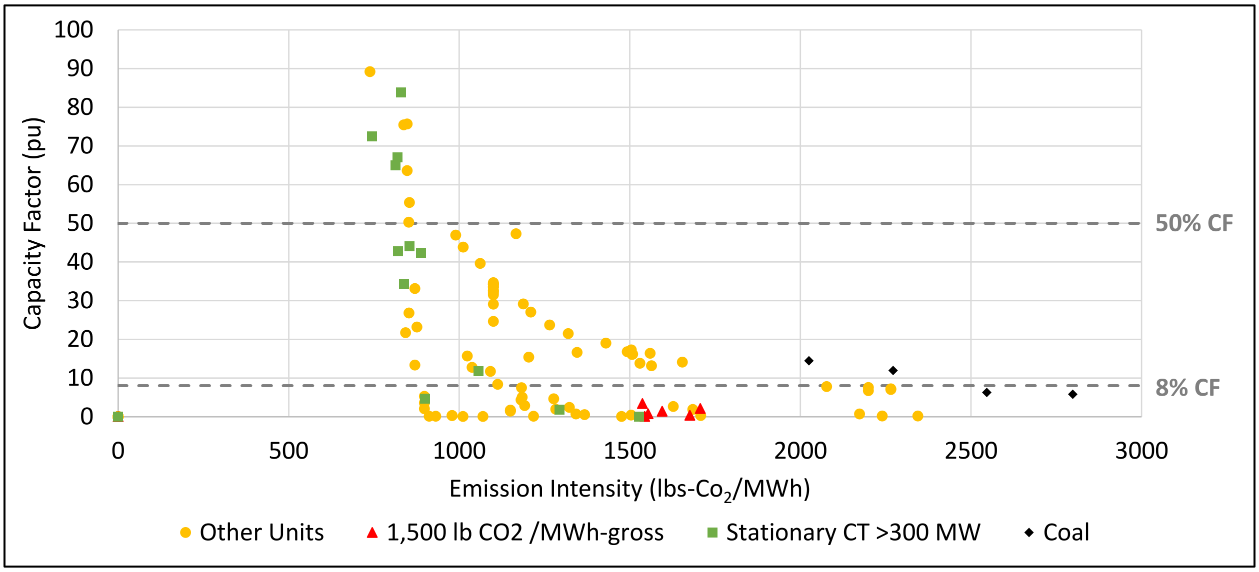

Figure 1. CO_2 Emissions Intensity vs Capacity Factor in Baseline without EPA Rule

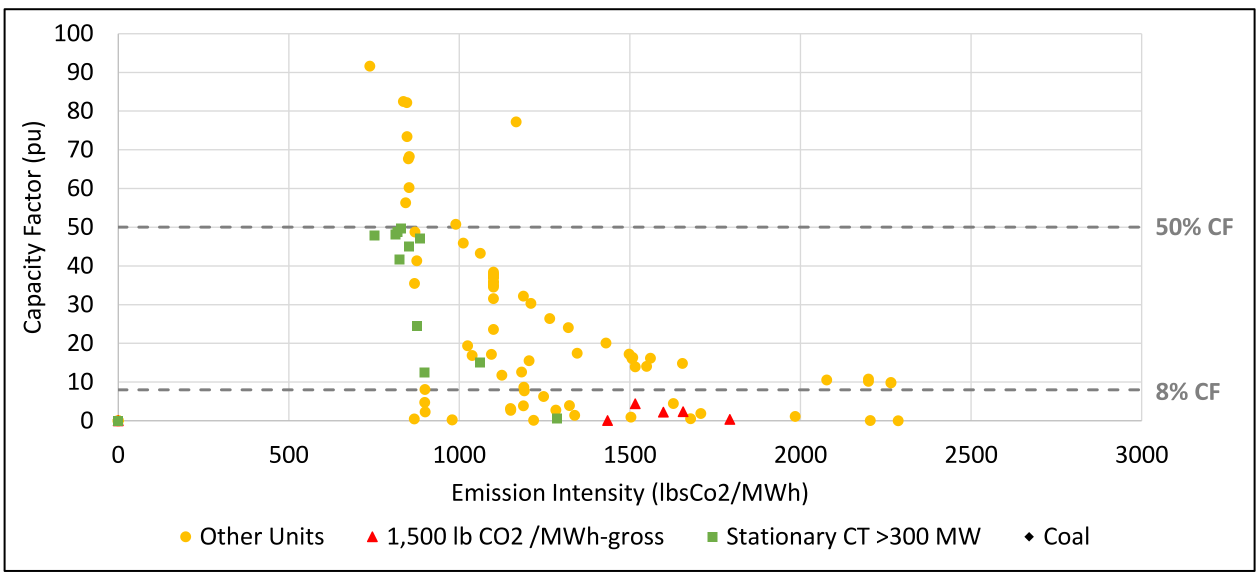

Figure 2. CO_2 Emissions Intensity vs Capacity Factor with EPA Rule Enforced

With a 50% capacity factor limit on natural gas stationary combustion turbines >300 MW, these EGUs largely pass the bulk of their generation to smaller, less efficient natural gas and oil burning EGUs. The largest changes in generation subtypes from the baseline scenario to when the EPA rule is enforced was a 0.967 TWh (0.23 million barrels of oil) or 35% increase in oil generation, 0.170 TWh or 9% increase in municipal solid waste and landfill gas (MSW/LFG) EGUs, and 0.168 TWh (4.34 billion cubic feet) or 0.4% increase in all natural gas generation. Figure 1 above shows the emissions intensity vs capacity factor for all fossil generation in the baseline scenario, while Figure 2 shows the same when the EPA rule is enforced. The dash lines across the graph represent the 50% capacity factor limit for natural gas stationary combustion turbines > 300 MW and 8% capacity factor limit for natural gas and oil boilers with emissions >1,500 lbs-CO_2 per MWh when the EPA rule is enforced. Comparing the two graphs shows the effect of enforcing these capacity factor limitations on their associated fleets in the EPA rule.

As noted earlier, it can be seen that natural gas and oil boilers with emissions >1,500 lbs-CO_2 per MWh already had a capacity factor below 8% before the proposed EPA rule was enforced. The respective capacity factors and emissions intensities change slightly when the proposed EPA rule is enforced, but this is largely due to changes in dispatch due to other provisions of the proposed EPA rule.

The largest impact of the EPA rule in New England is the 50% capacity factor limit on natural gas stationary combustion turbines >300 MW. Those EGUs see a 19% reduction in annual energy accounting for 8 TWh of energy, while the other natural gas stationary combustion turbines <300 MW see a 119% increase in operation totaling 6 TWh of energy. The remaining 2 TWh of energy difference was taken up by Municipal Solid Waste (MSW), Landfill Gas (LFG), and oil burning EGUs. When comparing Figure 1 to Figure 2, it can be seen that the natural gas stationary combustion turbines >300 MW have their capacity factors all decreased to at or below 50%, while all other EGUs that are not covered by the proposed EPA rule see an increase in their capacity factors. It can be concluded that the enforcement of the proposed EPA rule would not reduce fossil generation; rather, the proposed EPA rule would shift the generation burden from larger, more efficient natural gas plants, to smaller and less efficient natural gas and oil EGUs.

Varying the nameplate thresholds and maximum capacity factors of stationary combustion turbine only increases the generation on EGUs that are unaffected by the EPA rule. Figure 3 below shows the nameplate-weighted capacity factors for all dispatchable, carbon-emitting EGUs. It can be noted that implementing a 50% capacity factor to stationary combustion turbines leads to a decrease in generation within that classification of EGUs, but an increase in all other groups of generation with the exception of retired coal. Reducing the capacity factor to 40% only exacerbates the effect seen with a 50% capacity factor.

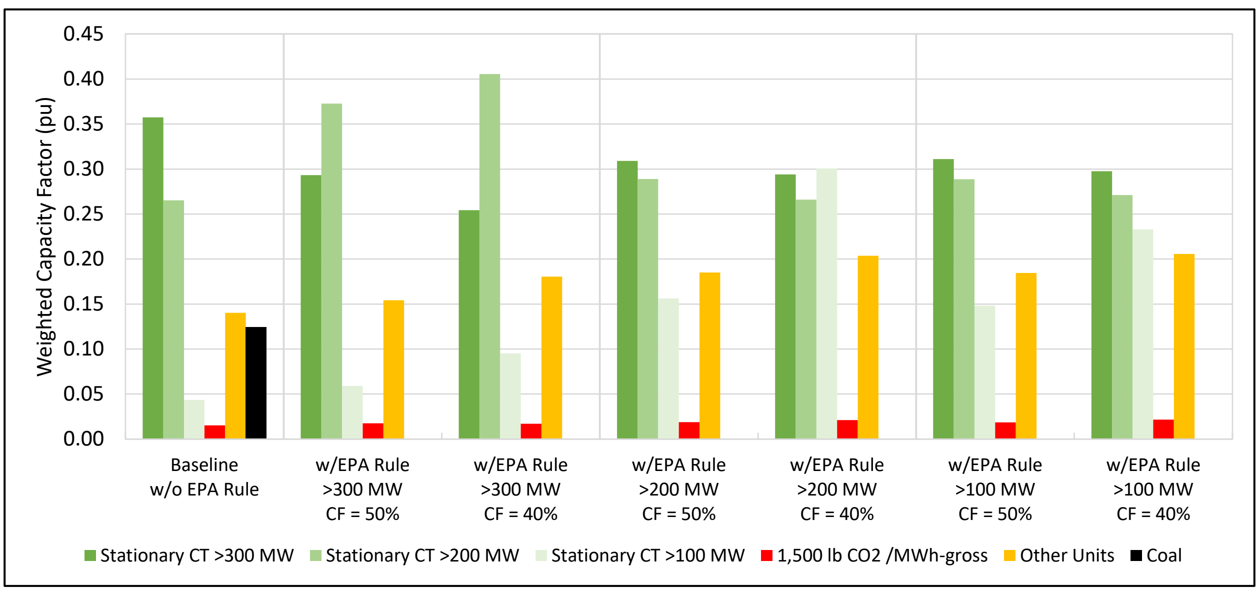

Figure 3. Nameplate-Weighted Annual Capacity Factor by Generator Classification

This trend continues as the nameplate threshold on stationary combustion turbines falls to EGUs >200 MW and >100 MW. EGUs that are facing a capacity factor limitation tend to see a decrease in generation while EGUs that do not face a limitation in capacity factor tend to see an increase in generation. Similarly, reducing the capacity factor limitation from 50% to 40% tends to increase generation not facing restrictions while reducing generation of EGUs that do fall under restrictions.

Of particular concern is the continued increase of ADR when nameplate thresholds and/or capacity factors are reduced from 300 MW and 50% capacity factor. When the nameplate threshold is dropped from 300 MW to 200 MW, a relatively similar 32 GWh (an increase of 721% from the baseline) of ADR is seen. By dropping the nameplate threshold to 100 MW, a concerning 41 GWh (an increase of 936% from baseline) ADR is observed. Similar increases in ADR were also observed. As mentioned previously, ADR represents voluntary customer load curtailment that only kicks in at $1,500/MWh. While production cost modeling does not produce resource adequacy metrics, it can indicate potential capacity shortfalls that may put the system below reliability criterion. By observing significant active demand response in these production cost simulations, it is highly likely that there are serious reliability concerns operating a system under these proposed restrictions of stationary combustion turbines. The ISO would have preferred to run a full resource adequacy analysis to quantify the effects this rule has on the reliability of the region, but that is a very labor-intensive process that was impossible to undertake under the given comment period timeline.

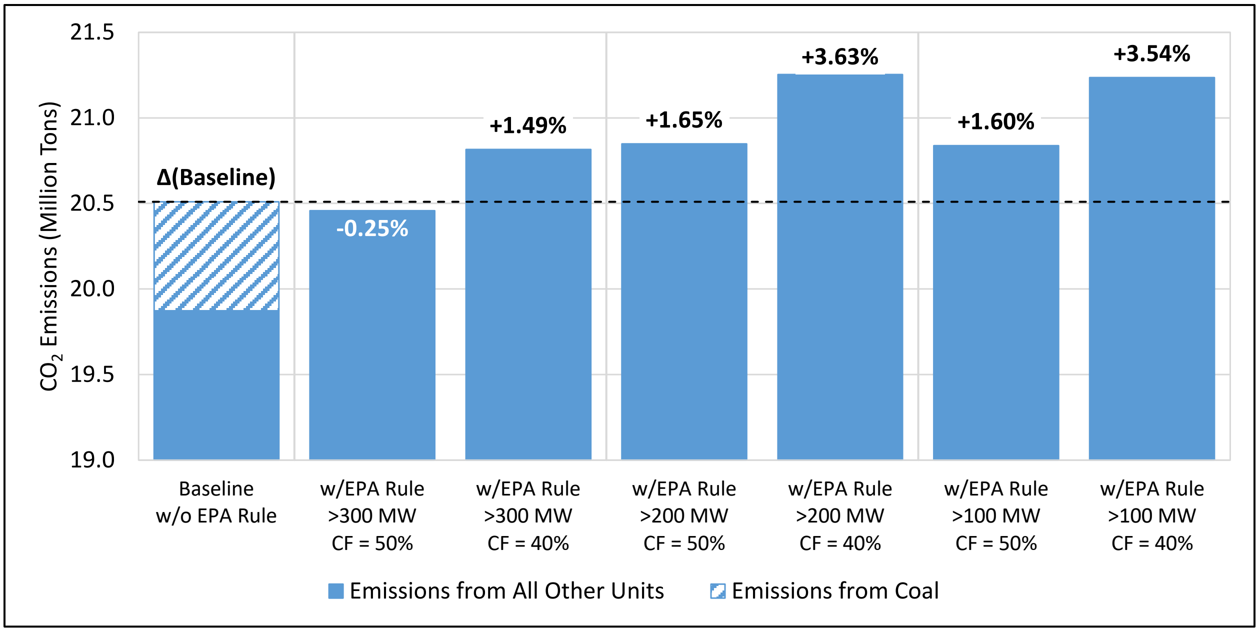

Figure 4. Annual Emissions vs Baseline Emissions

The result of shifting generation from larger combustion turbine EGUs to smaller, generally less efficient carbon emitting EGUs is an increase in annual carbon emissions. While enforcing a 50% capacity factor to stationary combustion turbines over 300 MW saw little change in system wide emissions, reducing the capacity factor to 40% and/or reducing the nameplate threshold to 200 MW or 100 MW resulted in an increase in carbon emissions. Since this proposed rule restricts the operation of the most efficient natural gas EGUs within the New England region, smaller less efficient EGUs that do not fall under similar limitations will increase their production leading to more carbon emissions. Changing the nameplate thresholds and capacity factor limitations only serve to increase emissions on the system and potentially decrease system reliability.

V. RECOMMENDATIONS

The ISO respectfully provides the following recommendations for EPA's consideration as it continues to develop its proposed rules.

First, the ISO respectfully recommends that the EPA clarify which data source should be used for nameplate capacity when determining EGU applicability under the currently proposed rule and any additional proposed rule. Various sources publish nameplate capacity including the ISO, EPA Clean Air Markets Program Database, and the U.S. Energy Information Administration (EIA). The values vary across these sources and, as shown in the ISO's analysis, the difference between the EPA and the ISO nameplate values is significant. The ISO has decided to use nameplate capacity values in its annual CELT report in its analysis, which forecasts future capacity, energy, loads, and transmission needs. The main difference between the ISO and EPA's data is that ISO's data is future looking and reflective of EGUs' physical capabilities whereas EPA's data is based on historical reporting. The EIA Form 860 also provides generator-level capacity data, but there is a two-year lag in the data release. The EPA should provide clarification on when it is appropriate to use a specific data source over the other to avoid confusion.

Second, the ISO respectfully recommends that, in this proposed rule and subsequent rulemaking that will cover the remaining natural gas fleet, the EPA consider the level of emission reductions that can be achieved through the use of other technologies. For example, low carbon fuels such as synthetic methane and synthetic/renewable natural gas can be used as a direct replacement for fossil gas and are compatible with existing natural gas infrastructure. Low carbon fuels can be produced from multiple sources including conversion of biomass, valorization of waste feedstocks, and methanization using hydrogen and captured CO_2.[7] The use of these fuels would not increase emissions since the combustion emissions would be equal to

[7] "Electric-Gas Infrastructure Planning for Deep Decarbonization of Energy Systems," MIT, accessed July 2023.

the CO_2 captured during its production resulting in a carbon-neutral fuel. Low carbon fuels coupled with additional smokestack controls and heat rate improvements could potentially reduce emissions while mitigating costs on the distribution and customer ends. The ISO respectfully request that EPA consider these and other alternate pathways in the current and subsequent rulemakings.

Third, the EPA is soliciting comments on whether the capacity and capacity factor thresholds for stationary combustion turbine EGUs should be lowered to 100 MW or 200 MW and 40% capacity factor. At this time, the ISO's analysis shows that the current proposed thresholds of >300 MW and >50% capacity factor had a slight net reduction in emissions. However, once the capacity factor threshold was lowered to 40% and nameplate capacity below 300 MW, the resulting effects were a net increase in emissions due to increase generation from smaller and less efficient EGUs and increase reliance on voluntary customer load curtailment via ADR. Therefore, the ISO respectfully recommends that the EPA does not lower the proposed nameplate capacity and capacity factor thresholds below what is currently being proposed.

Fourth, the ISO supports the EPA's proposal to require owners or operators of affected EGUs to post all reporting and recordkeeping information on a publicly accessible website. To reduce reporting redundancy and avoid having multiple websites for each affected generator, the ISO suggests the EPA establish a single centralized website for all affected generators to post this information.

Fifth, while the ISO/RTO Council had submitted a formal request for a 60-day extension to the comment period[8] for the proposed rule, the EPA only granted a 15-day extension, which does not allow sufficient time for a thorough evaluation of the proposed rule and an in-depth

[8] "ISO/RTO Council Extension Request", Regulations.gov, accessed July 2023.

analysis on its impact to grid reliability. Due to the complexity of this proposed rule and the significant impact that it can have on the bulk power system, the ISO respectfully requests that the EPA provide another comment period before the rule is finalized to allow the ISO more time to perform further analysis. In addition, the ISO respectfully requests that the EPA provide ample time to comment on any subsequent rulemaking, particularly, on the upcoming rule pertaining to the remainder of the natural gas fleet.

Finally, as already stated above, as EPA continues to develop its proposed rules, the ISO respectfully requests that the EPA coordinate technical conferences with Independent System Operators/RTOs and FERC to address reliability concerns specifically pertaining to these proposed emission guidelines.

Respectfully submitted,

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