Analysis of Combustion Turbine CO_2 Emission Rates Under the 2024 Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for Fossil-Fired EGUs

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Section 1 Introduction and Summary

On June 17, 2025, the Environmental Protection Agency (EPA or Agency) issued its proposed *Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units* rule.[1] The Proposed Rule, under its primary approach, seeks to repeal all greenhouse gas (GHG) emission standards for fossil-fueled power plants. EPA is also proposing, as an alternative, to repeal a narrower set of requirements. However, among other items under the alternative approach, the Agency is not proposing to revise the "Phase 1" carbon dioxide (CO_2) new source performance standards for stationary combustion turbines (CTs).[2] Rather, the Agency is soliciting comments on the best system of emission reduction (BSER) or standards of performance and related requirements for new and reconstructed intermediate load and low load fossil-fired stationary combustion turbines (Alternative Proposal C-13 and C-14, respectively). The current Phase 1 performance standards are based on a 12-month rolling average rate in pounds of CO_2 per megawatt hour (lbs/MWh), the specific values of which depend on (1) the 12-month capacity factor (i.e., low, intermediate, and base load) and (2) fuel. This analysis examines CO_2 rates for natural gas-fired simple-cycle CTs (in the intermediate load category) and combined-cycle CTs (in the base load category). Similar concepts would apply to other fuels, including diesel oil.

This report provides comments (in response to Alternative Proposal C-13 and C-14) based on publicly available information, including the current rule issued May 4, 2024[3] and the associated rulemaking docket.

A review of this material shows EPA's methodology for selecting Phase 1 standards for simple cycle and combined cycle CO_2 emission rates is flawed, as is the economic evaluation upon which EPA relied to draw the line for base load units (which EPA assumes are always combined-cycle units) at an annual capacity factor of 40%.

First, EPA does not account for how combustion turbine design variants affect CO_2 emission rate in the selection of an appropriate standard. Although EPA recognizes the different turbine designs – such as the E-, F-, H-, and J-Class and aeroderivative variants – the Agency does not consider such differences in selecting the CO_2 emission rate. The inherent emission rate differences between these various designs can be estimated, initially, by comparing the performance specifications of the combustion turbine suppliers (i.e., thermal efficiency—and therefore CO_2 emission rates—at high load under ISO[4] conditions), adjusted to account for the impact of a real world environment of non-ISO conditions; duty cycle; component degradation;

[1] 90 Fed. Reg. 25,752 (June 17, 2025) (Proposed Rule).
[2] More specifically, the current rule contains efficiency-based standards of performance for intermediate load CTs and as "Phase 1" standards for base load CTs. This report refers to both as the "Phase 1" performance standards.
[3] 89 Fed. Reg. 39,798 (May 9, 2024).
[4] ISO (International Organization for Standardization) conditions for testing combustion turbines are 15° C, 60% relative humidity, and sea level elevation.

ambient temperature; etc.[5] This analysis estimates both a "mean" and maximum" adjustment to apply to the high-load, ISO thermal efficiency specified by the supplier, and finds the median adjustments of 13-16% and maximum adjustments of approximately 22-24% comport with actual data measured for different turbine design categories.

Second, reviewing CO_2 emissions obtained from the EPA Air Markets Program Data (AMD) and the specific CTs show that complying with the present CO_2 emission rates is not based on broadly available technology. Specifically, many simple cycle CTs operating between 20% and 40% capacity factor are challenged to meet the emission rate of 1,170 lbs/MWh, as it is derived from an unrepresentative subset of units. Similarly, the present limit for CTs in combined cycle and at base load of 800 lbs/MWh (up to 900 lbs/MWh for small units) is not based on broad industry practice or available options. Specifically, for simple cycle CTs, the CO_2 emission rate is based on the aeroderivative class, despite EPA intending this rate to be applicable to frame turbines designed to generate seven times more power. EPA cites three aeroderivative turbine designs by supplier and model – two reflecting the very best thermal performance by any simple-cycle CT – and effectively requires that all units in the population (even those seven times larger, with very different designs) meet the same limit. There are many differences in the design attributes of aeroderivative turbines that distinguish them from large frame units that cannot be "scaled" to larger sizes. Most noteworthy, EPA does not recognize that aeroderivative units (which are typically small) can employ air compressors that create combustor inlet pressures up to 45 times that of the ambient air, elevating thermal efficiency by 2-3 percentage points above that achievable by frame turbines of intermediate generating capacity (150-350 MW). The broad population of simple cycle turbines cannot achieve such thermal performance. The net result of the current intermediate-load standard is largely to prohibit the construction of some aeroderivative CTs and most E-, F-, H-, and J-Class frame CTs (except perhaps the very largest H-Class units) for intermediate load duty.

Regarding combined cycle applications, EPA notes the actual CO_2 emission rate of the population ranges from 720 to 920 lbs/MWh, averaging 810 lbs/MWh. EPA implements so-called "adjustments" to the CO_2 emissions from these plants, correcting for different arrangement of combustion turbines and steam turbines. These adjustments range from accounting for a 1% advantage for a 2x1 arrangement compared to a 1x1 arrangement, a 1.4% advantage of wet versus dry cooling towers, and estimating any emissions increase observed at 40% duty cycle.[6] After these corrections, EPA then reverts to identifying the Dresden Plant in Ohio as a "best-performing" unit, emitting 770 lbs/MWh, enabled in part by the use of a wet cooling tower for which obtaining a permit in the present environment is challenging. EPA

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[5] Gas Turbine World 2025 Performance Specs. Hereafter GTW 2025. https://gasturbineworld.zinioapps.com/reader/readsvg/658297/Cover. Note that CO2 emission rates are a direct function of a CT's thermal efficiency, or heat rate. This report uses a conversion factor of 117 lb CO_2 lb/MMBtu.

[6] As EPA uses the term, "'duty cycle' is the ratio of the gross amount of electricity generated relative to the amount that could be potentially generated if the unit operated at its nameplate capacity during every hour of operation. Duty cycle is thereby an indication of the amount of cycling or load following a unit experiences (higher duty cycles indicate less cycling, *i.e.,* more time at nameplate capacity when operating). Duty cycle is different from capacity factor, as the latter also quantifies the amount that the unit spends offline." 89 Fed. Reg. at 39,853 n.359.

concludes the revised database and experience from Dresden justify a CO_2 emission rate of 800 lbs/MWh rate. In doing so, EPA does not explain why any unit that does not use the specific design of the Dresden CTs, that is subject to different ambient or operating conditions than Dresden, and that is operated differently than Dresden (for example, experiencing more startup and shutdown cycles, more frequent load changes, or operation at a lower operating factor) can meet the selected standard.

Finally, EPA in the 2024 rulemaking employed a 2023 NETL study[7] to create numerous reference cases to justify 40% capacity factor as the intermediate load threshold. An overarching concern is that such "static" studies do not always reflect the present marketplace, and can be misleading. In other words, the results of EPA's own study could be very different in the future, if natural gas prices change, for example, or for a number of other reasons. Separate from that concern, EPA had to create four "new" reference cases to support its position by implementing numerous extrapolations and adjustments to the NETL reference cases, almost all of which introduce significant error. These "new" reference cases created by EPA compare the levelized cost of electricity (LCOE) from a simple and combined cycle unit. Results show these units generate equivalent LCOE at 40% capacity factor – but just barely, and likely not supported by the margin of error, as differences range from negligible to 2%. Based on the trends in LCOE extrapolated from the NETL study, EPA established a yearly capacity factor of 40% as the cutoff between intermediate load and base load categories, in effect mandating that any new simple-cycle CT is prohibited from operating at a capacity factor higher than 40%.

This analysis presents an alternative approach to analyzing LCOE at different capacity factors, using a more recent Energy Information Administration (EIA) study.[8] This approach requires only a modest extrapolation to create one "new" reference case. The sole extrapolation scales capital cost and operating variables of a 650 MW combined cycle to 450 MW – well within the range of generally accepted scaling criteria. No other adjustments or extrapolations are required. These EIA-derived results show that for conditions of unit lifetime, scaling factor for capital cost, and natural gas price only slightly different from EPA's but equally reasonable, simple cycle and combined units generate at equal LCOE at greater than 50% capacity factor. Consequently, the use of 40% capacity factor as the threshold for practically requiring a combined-cycle configuration is not justified.

After this introductory section, four additional sections comprise this report. Section 2 presents the results of calculations using suppliers' specified heat rates, adjusted based on an industry observer data to reflect real-world duty. Section 3 presents actual results from the AMD as evaluated by EPA, and independently by this study. Section 4 identifies how EPA established the basis for the proposed CO_2 emission rate limits for simple and combined cycle CTs. Section 5 critiques EPA's economic study used to justify the 40% capacity factor threshold for base load operations and performance standards (i.e., simple-cycle prohibition), and introduces an alternative approach.

[7] Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, National Energy Technology Laboratory, May 2023.
[8] Energy Information Agency, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, January 2024.

Section 2. Combustion Turbine Supplier Performance Specification

Introduction

Section 2 provides background information that demonstrates how the design of a combustion turbine (CT) fundamentally determines the CO_2 emission rate per MWh of output for any particular CT. The thermal efficiency of the combustion turbine drives the CO_2 emission rate of a CT. Each CT has an inherent thermal efficiency, typically expressed in terms of British Thermal Unit (Btu) per kilowatt-hour of output (Btu/kWh). This metric is also referred to as heat rate, typically specified by the manufacturer at full-load, under ISO conditions. At any given point in time, however, the thermal efficiency of the CT is affected by a multitude of factors, among them: (1) the operating load; (2) degradation (both unrecoverable and between maintenance cycles); (3) altitude; (4) ambient temperature; and (5) design margin. Simple-cycle CTs are also affected by inlet/outlet pressure losses, while combined-cycle CTs are also affected by air inlet fouling and steam condenser conditions.

This discussion provides key background information describing how the five major categories of combustion turbine design – aeroderivative and four "frame" classifications – compare. The analysis starts with suppliers' performance specifications for commonly deployed combustion turbines in both simple and combined cycle, operating at ISO, full load conditions. These data are subjected to two comparisons. First, these theoretical (specification) performance metrics are adjusted to reflect real-world operation due to changes in load, ambient temperature and elevation, component wear, inlet compressor fouling, and other factors. These adjustments are implemented based on experience assimilated by the industry trade publication, the *Gas Turbine World 2025 Performance Specs* report, and a technical paper by a supplier. Second, the adjusted performance specifications are compared to CO_2 emissions as calculated from EPA Air Markets Program Data (AMD)[9] for commercially operating units, per turbine frame design.

Combustion Turbine Population

The *Gas Turbine World 2025 Performance Specs* report describes performance data for the population of combustion turbines generating 25 MW or more and operating at 60 Hz.[10] The report introduces adjustment factors addressing the impact of operating load, startup and shutdown, ambient temperature, site elevation, component wear, and other factors. The authors note these adjustment factors should not be used to base a design or component selection, but to

[9] Strictly speaking, CO_2 is not directly measured but determined from assumed heat content, fuel flow and EPA's CO_2 emission factor for natural gas (i.e., 117 lb CO_2/MMBtu for pipeline-quality natural gas).
[10] GTW 2025. https://gasturbineworld.zinioapps.com/reader/readsvg/658297/Cover.

provide insight that should be validated by contact with the supplier, or further study.[11] Additional insight into the role of several of factors is also provided by publications in the trade press[12] and by a supplier of combustion turbines.[13] This evaluation uses the *Gas Turbine World 2025 Performance Specs* adjustments to provide insights into the likely ability of various CT models currently available on the market to meet the 2024 Phase 1 standards, assuming their operation and other conditions are within the experience reflected in these publications.

For the purposes of this evaluation, a subset of combustion turbines consisting of 27 units in simple cycle mode is considered from four suppliers. Table A-1 in Appendix A provides the suppliers' specification for generating capacity and heat rate for these units. A total of 22 of these same combustion turbines are arranged by their suppliers in a combined cycle mode, representing over 40 different generating units. Table A-2 summarize these units according to various arrangements with heat recovery steam generators (HRSG) and steam turbines. For example, combustion turbines can be configured in a "1 x 1" arrangement (e.g. 1 combustion turbine, HRSG, and steam turbine) or a "2 x 1" arrangement with two combustion turbines/HRSGs and one steam turbine. Appendix A also includes several "3 x 1" arrangements.

The CO_2 emission rate is calculated from the supplier specification, per usual practice reported in terms of Lower Heating Value (LHV) of the fuel. EPA's CO_2 performance standards, however, are based on fuel carbon content per Higher Heating Value (HHV). Consequently, this analysis will (a) employ a fuel carbon content of 117 lbs/MBtu HHV,[14] and (b) adjust the heat rate specified by suppliers by a nominal 11% to account for the difference in natural gas HHV versus LHV. Using the CO_2 content of natural gas, CO_2 emission rates from simple and combined cycle units are calculated under the specified conditions (ISO, full load, new and clean surfaces, and no component wear).

Operating Factors

The CO_2 emission rate is calculated using supplier specification (as discussed above) and adjusted to reflect real-world operating conditions, as reported in the *Gas Turbine World 2025 Performance Specs* and a technical paper by a supplier.[15] These adjustments are summarized in Table 2-1 for simple cycle[16] and Table 2-2 for combined cycle.[17]

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[11] Ibid. For example, regarding the role of operating load on unit heat rate, the authors note the following on page 7. The curves presented here are intended only for instructive and preliminary estimating purposes. When appropriate in your studies, contact OEMs for a complete and accurate analysis…".
[12] The role of ambient temperature and altitude also described in literature: https://www.power-eng.com/operations-maintenance/why-keeping-cool-keeps-output-high/
[13] Advanced Technology Combined Cycles, GE Power Systems, GER3936A. Hereafter GE3936A.
[14] Small changes in natural gas carbon will change CO_2 generation rate. EPA assumes a fixed carbon content from natural gas and 100% conversion to CO_2 to establish the carbon balance for Part 75 calculations. Natural gas carbon content is affected by the content of higher carbon constituents and lower hydrogen-content constituents such as pentane, can alters CO_2 generation rate per MBtu.
[15] GE3936A
[16] GTW 2025. At 7.
[17] Ibid. At 18.

Table 2-1. Simple Cycle "Real World" Heat Rate Impacts: Operating Factors

Factor	Heat Rate Impact	Mean Impact (%)	Maximum Impact (%)
Operating Load (fraction of capacity)	4% increase in heat rate at 80% load[18]	3.5	8
Degradation	2-6% loss in 24,000 hrs; restorable to within 1-1.5% of design	4	6
Altitude[19]	3.5% loss in power = each 1,000 ft above sea level		
Ambient temperature	0.1% increase in heat rate = each 1ºF above ISO	0.5	1.6
Inlet/Outlet losses per incurred air or gas pressure drop	0.2% increase in heat rate with each 1 inch w.g. increase in inlet/output pressure drop	0.8	1.6
Design Margin	3-5%	4	5
Total		12.8	22.2

Table 2-2. Combined Cycle "Real World" Heat Rate Impacts: Operating Factors

Factor	Impact	Mean Impact (%)	Maximum Impact (%)
Operating Load (fraction of capacity)	4% increase in heat rate per cycling, frequent startup/shutdown.	4	6
Degradation	3-5% loss in 10-15 Years	4	5
Altitude	0.2% increase in heat rate = each 1,000 ft above sea level	0	1.2
Ambient temperature	0.5% higher heat rate = per 10ºF above ISO	0.25	0.8
Air Inlet Fouling	1.2% increase in heat rate, not recoverable	1.2	1.8
Condenser (Heat Removal)	1% increase in heat rate per 0.5-inch Hg absolute pressure[20]	2 (per 1.0 in Hg	4 (per 2 in Hg
Design Margin	3-5%	4	5
Total		15.5	23.8

[18] GE3936A. Figure 3.
[19] Altitude results in a loss of maximum power output for a simple cycle combustion turbine, as reported above. It is unclear whether altitude also affects heat rate. This evaluation assumes no impact on heat rate from altitude.
[20] Ibid. Table 1 describes "new and clean" as 1.2 in Hg absolute; means and maximum impact values assumed as 1 and 2 in Hg absolute, respectively.

Table 2-1 summarizes the detrimental effects on heat rate for simple cycle combustion turbines due to five operating factors. These include operating load, component degradation, host site altitude, annual ambient temperature, and combustion air intake pressure drop. For each of these operating factors, the range cited in the *Gas Turbine World 2025 Performance Specs* augmented with a combustion turbine supplier's paper is reported. Two example cases are defined, reflecting "mean" conditions based on intermediate or mean values of the ranges listed in Table 2-1, and a "maximum" case based on the highest values in the range. The mean values of the heat rate detriment assigned are 3.5% for part load operation and startup/shutdown, 4% for component degradation, 0.5% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), and 0.8% for a total of 4 in w.g. inlet air pressure loss. Including an additional 4% compliance margin (intermediate to the 3-5% design margin offered by GE in comments submitted in 2024).[21] In total, a mean total detriment of 12.8% is estimated.

The maximum values observed are 8% for part load operation and startup/shutdown, a 6% for component degradation, 1.6% to reflect units with ambient temperature elevated by 20ºF (e.g. from 59 to 79ºF), and 1.6% for a total of 4 in w.g. inlet air pressure loss. Per GE recommendations, the additional design margin of 5% is assigned, resulting in a total 22.2% detriment. (An additional compliance margin is not included in these example cases).

Table 2-2 similarly summarizes the detriment to heat rate for combined cycle combustion turbines due to operating factors analogous to simple cycle, but accounting for steam cycle heat rejection. These include operating load, component degradation, host site altitude, annual ambient temperature, combustion air intake pressure loss, and fouling of the condenser dedicated to heat rejection. The cumulative detriment to heat rate based on the mean values in Table 2-2 is 4% for part load and startup/shutdown operation, 4% for component degradation, 0.25% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), 1.2% for inlet air fouling pressure loss, and an additional 2% to account for a 1 inch Hg absolute penalty in steam cycle condenser pressure drop. Including an additional 4% design margin (intermediate to the GE report of 3-5%) a total detriment of 15.5% is estimated.[22]

For the maximum values in Table 2-2, the cumulative detriment is 6% for part load and startup/shutdown operation, 5% for component degradation, 1.2% to reflect a unit at 6,000 feet of altitude, 0.8% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), 1.8 % to reflect inlet air fouling loss, 4% to account for a 2-inch Hg absolute steam cycle condenser pressure loss. The maximum margin of 5% as advised by GE is also included, resulting in a total 23.8% detriment.

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[21] GE Verona Comments, Docket No. EPA-HQ-OAR-2023-0072. At 48. Hereafter GE 2023 Comments.

[22] The role of operating factors on CO_2 emission rate, as documented by the *Gas Turbine World 2025 Performance Spec* and summarized in Tables 2-1 and 2-2, demonstrates CO_2 emission rate from any CT is determined not only by design but also by operating factors - many out of control of the operator. By basing the standards on the performance of certain units operating under specific operating factors (without accounting for the variability of factors outside the control of the operator or how operators may use their units differently elsewhere or in the future), EPA essentially incorporated these factors into its Best System of Emission Reduction (BSER) determination. This is inconsistent with the historical methodology, which depends primarily on process equipment design and performance, not restrictions on equipment operating factors.

CO_2 Emission Rates: As Calculated

The combustion turbine performance specifications and adjustments to heat rate due to operating factors, as defined in Tables 2-1 and 2-2, are used to calculate the CO_2 emission rate. These calculations are presented in Figures 2-1 and 2-2 for simple and combined cycle, respectively.

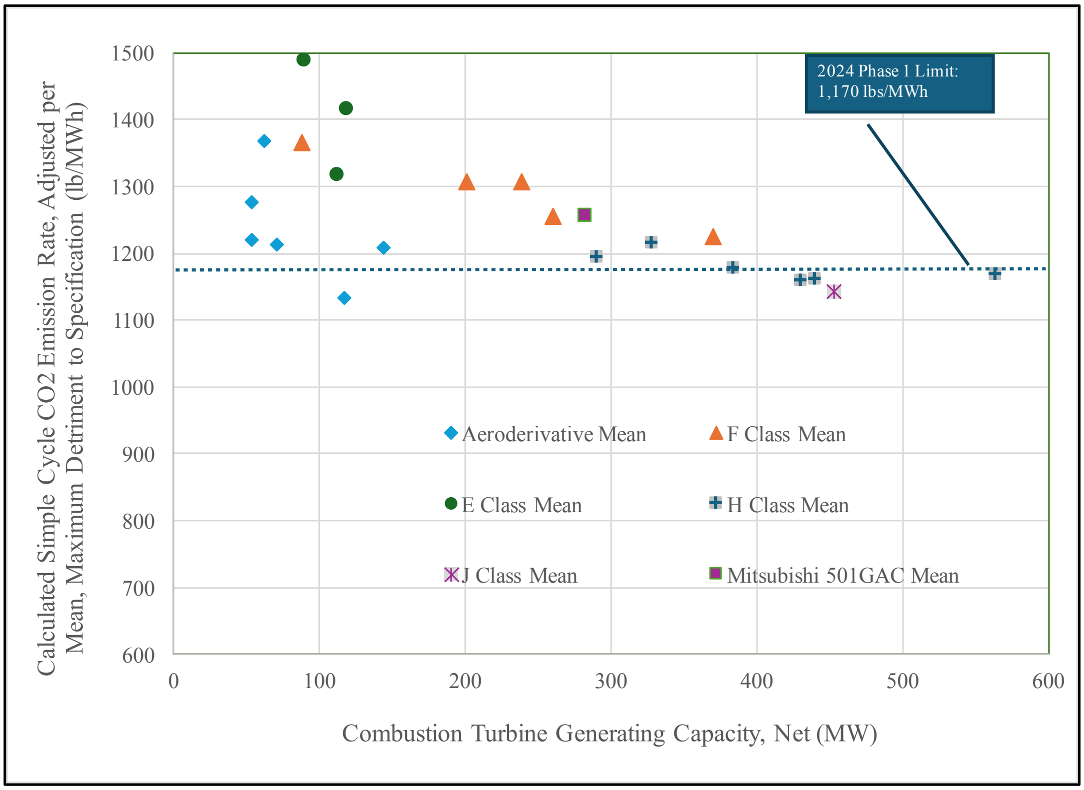

Figure 2-1. Calculated CO_2 Emission Rate: Simple Cycle

Simple Cycle

Figure 2-1 reflects the calculated CO_2 emission rate for the various combustion turbine designs designated in Appendix Table A-1. The mean value as determined from Table 2-1 is presented for each turbine classification, with data from each turbine class represented by the same marker and color. Figure 2-1 shows that based on the suppliers' specification and Gas Turbine World adjustments, a limited number of large H-Class, J-Class, and aeroderivative CTs, with the mean adjustment values are theoretically expected to have lower CO_2 rates than the current Phase 1 CO_2 emission standard of 1,170 lbs/MWh. However, no simple cycle CT with maximum adjustment (data not plotted for simplicity) can, even theoretically, meet the limit. A notable number of designs – in particular E-Class and F-Class models, and most aeroderivative designs – have specification CO_2 emissions rates adjusted by the mean value equal to or exceeding the 2024 Phase 1 CO_2 standard of 1,170 lb/MWh.

As a result, it appears that the 2024 Phase 1 CO_2 emission standard of 1,170 has the effect of prohibiting the use of a significant number of CT designs – several aeroderivative; all E-Class and F-Class, and most H-Class – as simple-cycle CTs operating at intermediate load. These types of units are, effectively, relegated to low-load duty under the current rules.

Combined Cycle

The Figure 2-2 combined cycle CO_2 emission rates reveal a pattern like that for simple cycle CTs – some of the largest H-Class and J-Class units can theoretically emit at less than the CO_2 emission standard of 800 lbs/MWh for the mean adjustment to heat rate. Those CTs would have a very small compliance margin. All other CT designs would likely exceed the standard, even at mean adjustment. The calculated CO_2 emission rates using the maximum adjustment (data not plotted for simplicity) of all currently available CTs would exceed 800 lb/MWh. None of the E-Class or aeroderivative design combined cycle units can meet the 2024 Phase 1 standard for base load units (which increases to 900 lb/MWh for units with heat input less than 2,000 MMBtu/h), for either the mean or the maximum.

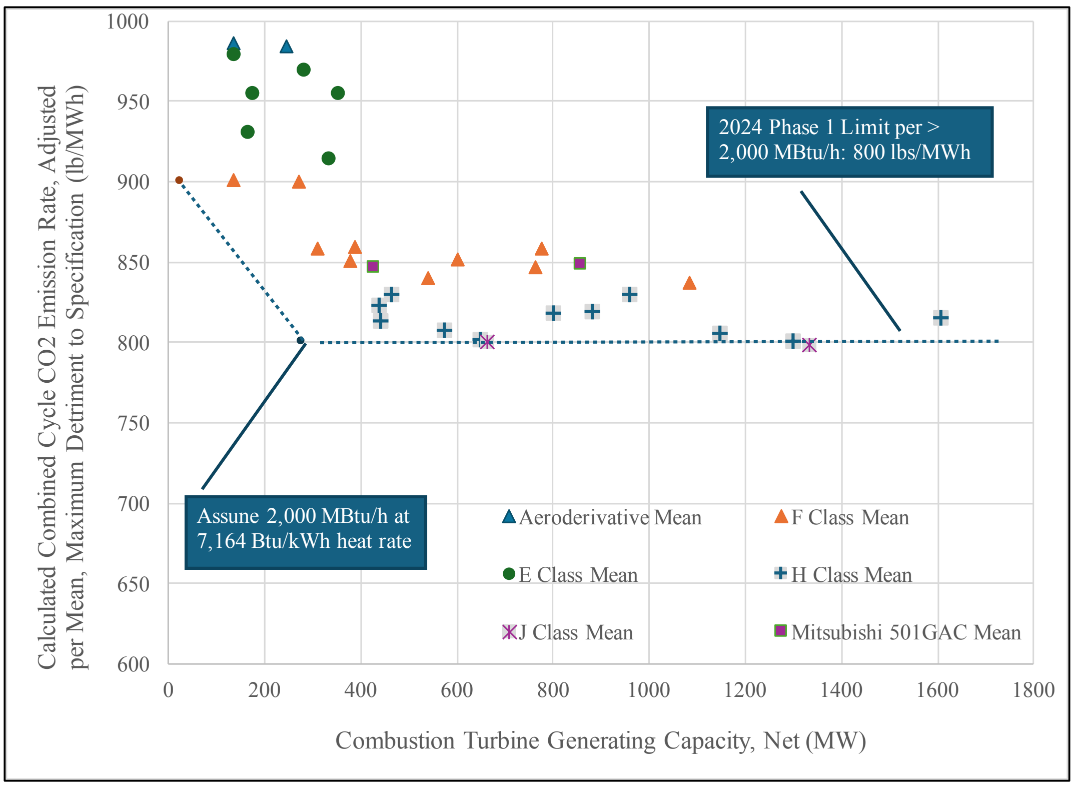

Figure 2-2. Calculated CO_2 Emission Rate: Combined Cycle

Reported Data

Reported actual CO_2 emission rates for combustion turbines is the third and possibly most significant comparison. Sections 3 and 4 of this report address data acquired from the EPA's AMD for two databases of populations of combustion turbines in the U.S. - one defined and used by EPA, and a second larger database used by this study. Prior to the Section 3 and 4 discussion of CO_2 emission rate trends with various operating factors, it is instructive to compare simple averages of CO_2 emission from the five design categories of turbine classes to those presented in

Figures 2-1 and 2-2. The results enable inferring an actual margin to compare with the observations offered by the *Gas Turbine World* and a supplier.

Both the EPA and this study considered simple and combined cycle units that commenced duty in 2015. Both the EPA and this study derived a database of reference units, which are screened to identify those simple cycle units operating at a minimum 12-month rolling capacity factor of 20%. EPA's database includes 87 simple cycle units of which 15 operated at 20% or more capacity factor, and 59 combined cycle units.[23] This study evaluated 146 simple cycle units of which 23 have operated at 20% capacity factor or more; and 72 combined cycle units. A further description of the differences in the databases is presented in Section 4. For both databases, the maximum CO_2 emission rate is determined over a 12-month rolling average.

The sources of data are as follows:

- Study Population: Commercial Service 2015-2023 natural gas-fired turbines CO_2 *Emission Rate = Sum of 2023-2024 CO_2 Mass (tons) divided by Sum of 2023-2024 Gross Load (MWh)*
- EPA Air Market Program Data: 2015 through 2023, Annual Basis
- EIA-860 – Unit Configuration, Size, Cooling Type, In-Service Date, Latitude/Longitude
- Capacity and Operating Factors: Same Basis
- Elevation Data: "Open Elevation" by lat/long
- Weather Data: "OpenMeteo" – annual, daily, hourly by latitude/longitude

The combustion turbine design category is not defined in these databases; such design information is acquired from files in EPA's Cross State Air Pollution Rule docket,[24] and augmented by a literature search and supplier information. These sources provide CO_2 emission from four of the five classes of turbines. The CO_2 emission rate and number of turbines in each design category are summarized in Figure 2-3 and the standard deviation of those emission rates are shown in Figure 2-4. These results are described as follows.

Simple Cycle

<u>Aeroderivative</u>. For 24 aeroderivative turbines operating at 20% capacity factor or greater, the CO_2 emission rate averaged 1,213 lbs/MWh. This actual, "as-observed" rate implies a real-world increase of 11% over the average of the suppliers' specification (i.e., at ISO and full-load) of 1,091 lbs/MWh. This average is relatively consistent with the 12.8% mean adjustment using *Gas Turbine World* and supplier data.

[23] EPA's database does not include generating units that entered commercial service after 2020; no rational is cited. This analysis, being able to access data through 2024, could include units that operated in 2021-2023 and have adequate data to calculate at least 12 data of 12-month rolling averages. Consequently, this study was able to utilize 78 additional units (69 simple cycle, 9 combined cycle).
[24] EPA EPA-HQ-OAR-2024-0419-0020_attachment_3. Available at https://www.epa.gov/Cross-State-Air-Pollution/cross-state-air-pollution-rule-csapr-regulatory-actions-and-litigation.

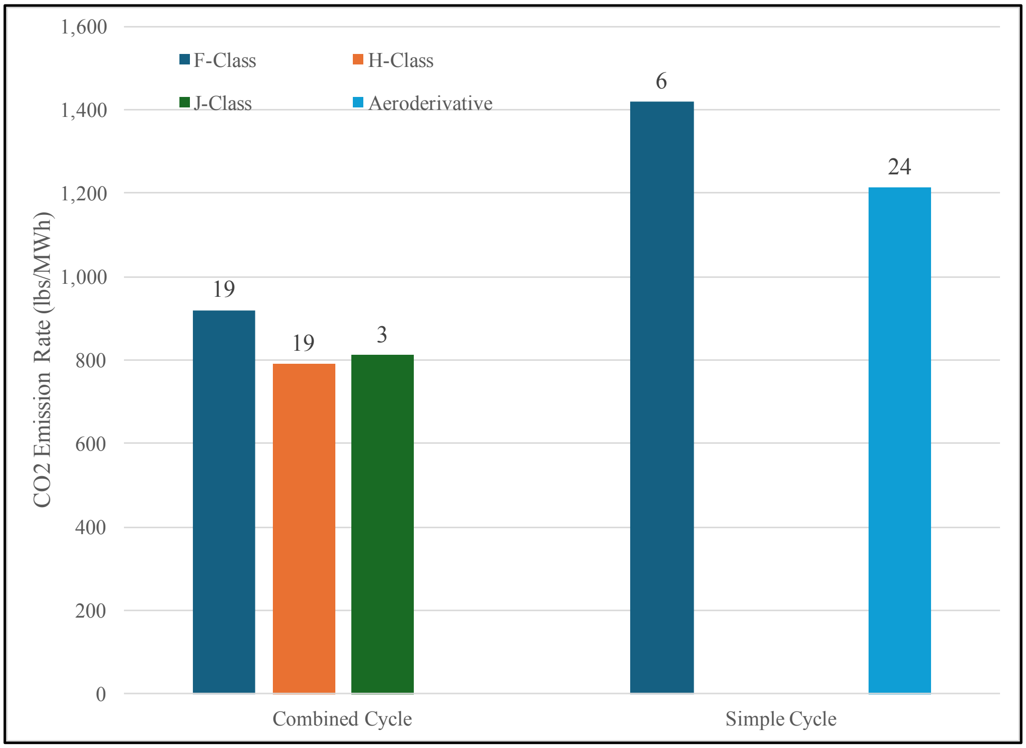

Figure 2-3. CO_2 Emission Rate from Turbine Design Categories: Simple, Combined Cycle

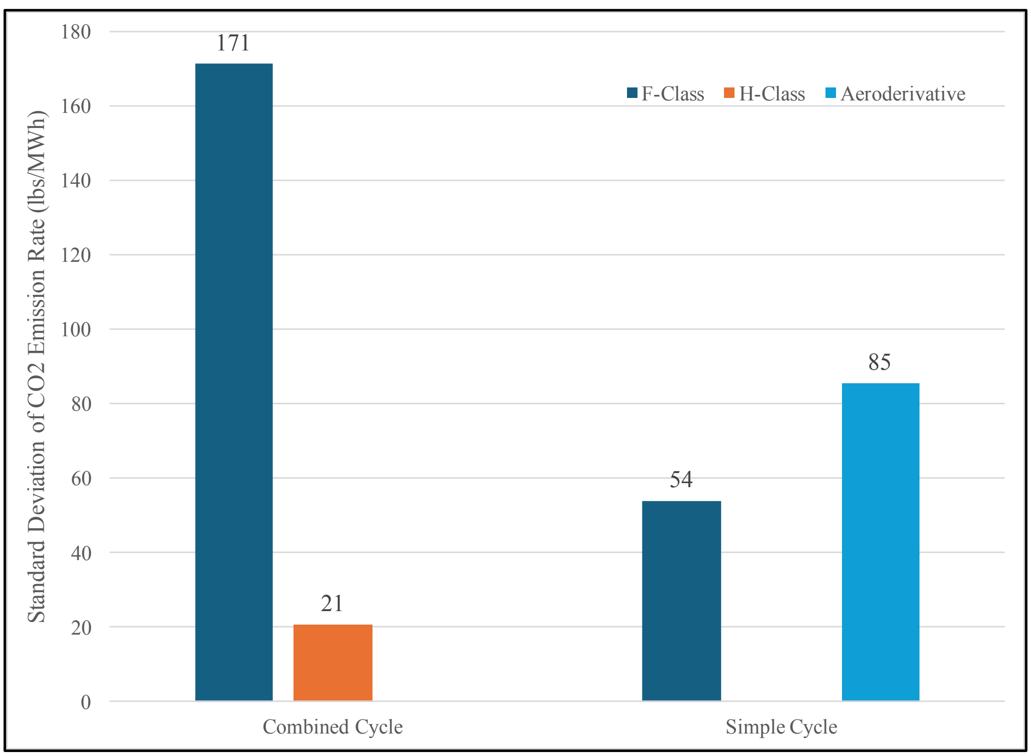

Figure 2-4 Standard Deviation of Maximum CO_2 Emission Rate per Categories: Simple, Combined Cycle

It is further insightful to consider the variability of this data by reviewing the standard deviation, or the CO_2 rate which 68% of the population either exceeds or is below the mean value. Figure 2-4 shows the standard deviation for the aeroderivative class is 85 lbs/MWh; implying nominally 7 units emit CO_2 at 1,298 lbs/MWh or greater, and the same number of units emit at 1,128 lbs/MWh or lower.

F-Class. These 6 units average 1,419 lbs/MWh of CO_2 emission, implying a 24% margin over the average of the suppliers' average specifications of 1,141 lbs/MWh. This real-world increase approximates the maximum of 22.2% of adjustment using *Gas Turbine World* and supplier data. These data exhibit a standard deviation of approximately 54 lbs/MWh; implying one or two units emit up to 1,453 lbs/MWh, and one or two 1,366 lbs/MWh or less.

Combined Cycle

The combined cycle data in Figure 2-3 are determined by design variables discussed previously. These are arrangements of the combustion turbine, HRSG, and steam turbine, and the use of wet or dry cooling tower. Sections 3 and 4 describe how these design variants affect the CO_2 emission rate.

F-Class. The 19 turbines within this category average CO_2 emissions of 920 lbs/MWh. The implied real-world increase for this category is 24% over the average specifications of 745 lbs/MWh, approximating the maximum adjustment of 23.8% using Gas Turbine World and supplier data. These data exhibit a relatively high standard deviation of 171 lbs/MWh, implying approximately 6 units emit more than 1,091 lbs/MWh, and the same number emit at 751 lbs/MWh or less.

H-Class. The 19 units comprising this category average 791 lbs/MWh of CO_2 emission. Many of these units are of the larger capacity 2 x 1 or 3 x 1 arrangement, biasing the CO_2 emissions rate low.[25] Any such bias to lower CO_2 is problematic for units with arrangement of 1x1, anticipated to be the most popular configuration. These emission rates imply a real-world operating increase of 12% over the average specifications of 706 lbs/MWh, approaching the mean adjustment of 15.5% using *Gas Turbine World* and supplier data. These data exhibit a relative small standard deviation of approximately 21 lbs/MWh.

J-Class. The three units present an average of 811 lbs/MWh; similar to H-Class these CO_2 emissions rates are influenced by combustion turbine and steam turbine arrangement. A real-world operating increase of 17% is implied, exceeding the mean adjustment using *Gas Turbine World* and supplier data. This population is too small to merit a meaningful standard deviation.

[25] Another complication of bias introduced by 3x1 and 2x1 arrangements is the impact when one or more turbines are off-line for service. This resulting configuration – even if operating for 4- 8 weeks –will affect the 12-month rolling average. This possibility is a basis for considering adequate design and operating margin in selection of CO_2 emission rate.

It should be noted that the use of duct burners, to increase power generation during periods of peak demand and adopted by approximately 75% of the combined cycle inventory,[26] can significantly affect heat rate. The heat rate impact can vary widely, from less than 1% to more than 3%.[27] However, the effect on the 12-month rolling average of CO_2 emission rate is less, as duct-firing is generally used only during periods of peak power and when justified by market electricity prices – perhaps 20% of operating time.[28] The data in Figures 2-3 and 2-4 probably reflects the impact of duct firing on the performance of the units in the population analyzed, although an explicit assessment of the contribution is not addressed in this evaluation.

Observations

Observations addressing the CO_2 emission rate specified by suppliers, with adjustments recommended by an industry trade publication to reflect "mean" and "maximum" expected real-world increases, and comparison to a sample of actual CO_2 data reported under the requirements of the Acid Rain Program (40 CFR Parts 72-75) are presented as follows:

- Calculated CO_2 emission rates, based on suppliers' design specifications and accounting for real-world heat rate impacts of operating factors, as observed by an industry publication, show CO_2 emission rates from simple and combined cycle duty vary considerably with the turbine design: aeroderivative, E-, F-, J-, and H- Class turbine.

- Observed CO_2 emission rates from a total of 30 simple cycle units, as derived from the AMD, imply an average adjustment factor to apply to the suppliers full-load/ISO CO_2 emission rate to reflect real-world data. The simple cycle data in Figure 2-3 imply an adjustment by approximately 11% for aeroderivative and 24% for F-Class units to reflect real-world operating duty. There is no data in AMD for E-Class and H-Class in simple cycle configuration. However, it is expected that both of these models will be used in these configurations in the near future and beyond.

- Observed CO_2 emission rates from a total of 41 combined cycle units, as derived from the AMD, imply an average adjustment factor to apply to the suppliers full-load/ISO CO_2 emission rate to reflect real-world data. The combined cycle data in Figure 2-4 imply an adjustment from 12% to reflect H-Class duty up to 24% to reflect F-Class duty.

The implications for meeting the 2024 Phase 1 standard for intermediate load (simple cycle CTs) and base load (combined cycle CTs) are summarized as follows:

- Simple Cycle. Figure 2-1 shows only one aeroderivative and several H- and J-Class units, using the calculated CO_2 emission rates based on the mean adjustment to specified heat rate, can meet the Phase 1 limit of 1,170 lbs/MWh; notably with little or no compliance margin. The use of the mean adjustment is corroborated by real-world data.

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[26] https://www.eia.gov/todayinenergy/detail.php?id=52778.
[27] The detriment to combined cycle unit heat rate due to duct burners is estimated to range from less than 1% to 3%. See https://www.power-eng.com/coal/combined-cycles-exploding-the-cookie-cutter-myth/.
[28] https://www.power-eng.com/gas/combined-cycle/advancements-in-duct-firing-technology/

- Combined Cycle. Figure 2-2 shows a limited number of F-, H-, and J-Class units can meet the CO_2 standard based of 800 lb/MWh, with little or no margin, based on suppliers' heat rate at ISO conditions and adjusted for mean detriments. The use of the mean adjustment is corroborated by real-world data.

Section 3. CO_2 Emission Rate Trends per Air Markets Program Data

Introduction

Section 3 reports trends in CO_2 emissions per MWh for both simple cycle and combined cycle units calculated from EPA's AMD. Data acquired from the AMD as used by (a) EPA to develop the 2024 Phase 1 Greenhouse Gas (GHG) New Source Performance Standards NSPS emission limits are presented, and (b) this study are both addressed. Differences in the universe of units evaluated are considered.

Both the EPA and this study derived databases of simple and combined cycle units that commenced duty in 2015 or later.[29] These databases considered all operating units, but for simple cycle only units operating at capacity factors of 20% or greater are considered in the evaluation. For combined cycle units, all but six operated at a capacity factor of 40% or greater and the units that operated at less than 40% capacity factor are excluded from the evaluation. The maximum CO_2 emission rate observed over the series of 12-month rolling averages since unit inception is calculated using the data sources listed in Section 2.

Reference Database

The database used by EPA differs from that utilized in this study. As described in Section 2, EPA's is comprised of 87 simple cycle and 59 combined cycle operating units.[30] This study identified 146 simple cycle and 69 combined cycle operating units. For simple cycle units that operate at 20% capacity factor or greater, EPA identified 17, while this study identified 23 units. Regarding combined cycle, all but six units in each database assembled by EPA and this study operated for at least one year above 40% capacity factor. Most of the difference in the population of the two databases appear to be due to a large number of units entering commercial service since 2021 that are not captured in the previous rulemaking by EPA.

Table B-1 in Appendix B lists the units in EPA's database not addressed in this study; Table B-2 lists units addressed in this study not considered by EPA.

Operating Features

Before considering the CO_2 emission rates of simple and combined cycle units, the characteristics of duty factor and operating factor are compared in Figures 3-1

[29] Units entering service in 2015 and thereafter likely reflect state-of-the-art technology, but (for the most recent of these units) may not capture the long-term role of component degradation with service time. Adequate margin in selecting CO_2 rates would address this uncertainty.
[30] EPA-HQ-OAR-2023-0072-0060_attachment_6

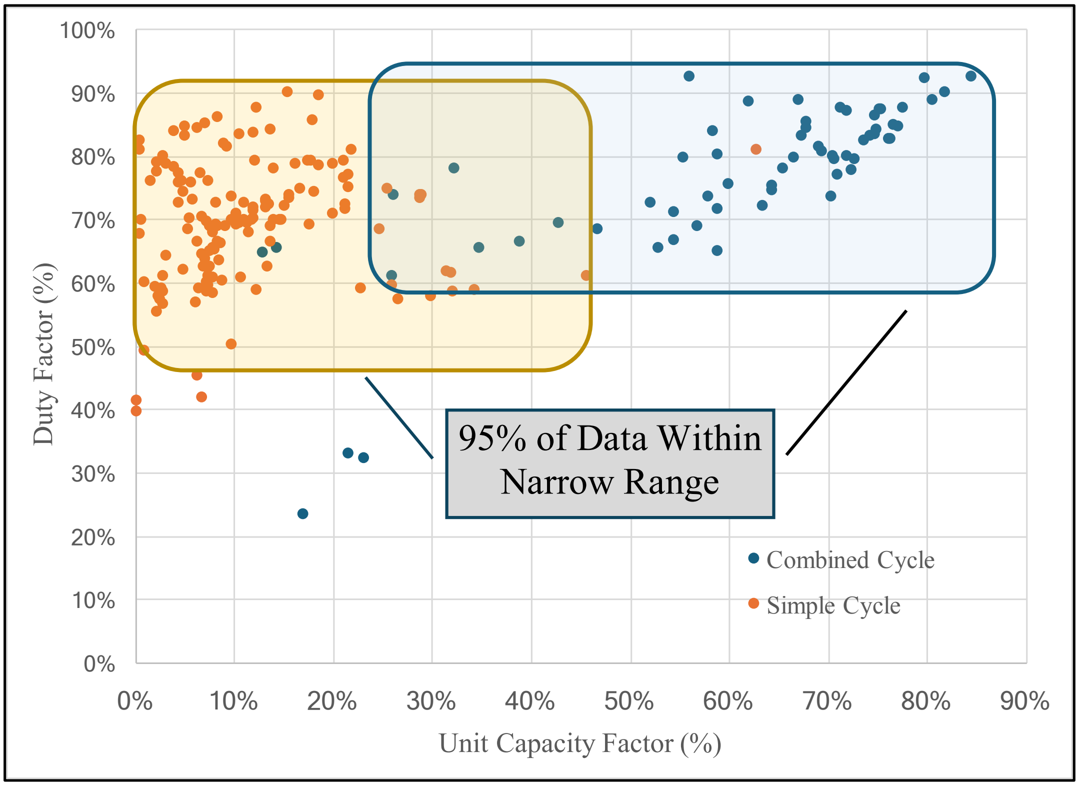

Figure 3-1. Combustion Turbine Operating Factor vs. Capacity Factor

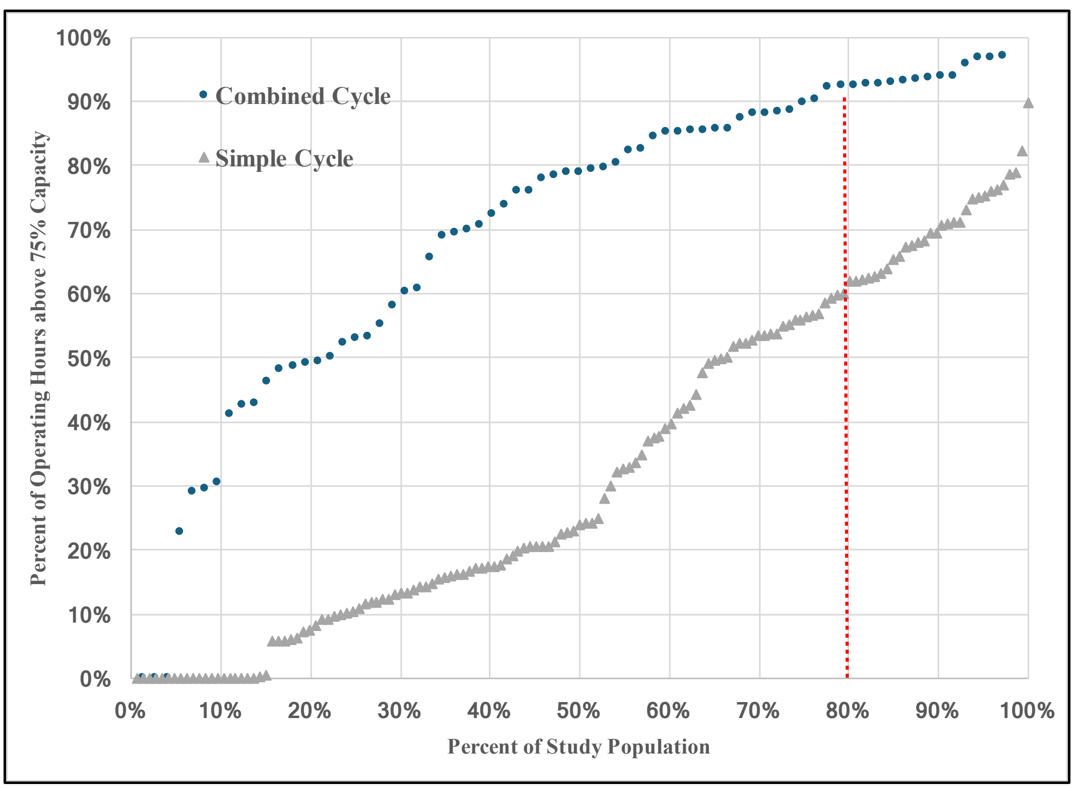

Figure 3-2. Percent Operating Hours Exceeding 75% Capacity: Simple, Combined Cycle

Figure 3-1 compares duty factor (what EPA calls duty cycle) and capacity factor for simple and combined cycle units addressed in this study, while Figure 3-2 reports the units' operations above 75% capacity factor. Figure 3-1 shows that although simple cycle units operate at much lower capacity factors than combined cycle, both types of units operate predominantly at high loads. The figure shows 95% of simple cycle units operate on average at 50 to 92% of maximum capacity (i.e., a duty factor of 50 to 92%). Combined cycle units exhibit a similar trend – 95% of units operate at an average of 58 to 94% of maximum capacity (i.e., a duty factor of 58 to 94%).

Figure 3-2 presents the cumulative frequency distribution of operating hours for simple and combined cycle units. Combined cycle units expend significant operating time at greater than 75% capacity – 80% of the units operate for 93% of the time as such. Eighty percent of the simple cycle units expend 60% of operating time at more than 75% capacity.

Additional discussion is presented according to each operating cycle as follows.

Simple Cycle

This study identified 146 simple cycle units firing natural gas from EIA and EPA sources as candidates for evaluation. Of this population, 30 units have operated between 20 and 40% capacity factor for at least one year, generating at least one relevant 12-month rolling average CO_2 emission rate. The maximum CO_2 emission rate for these 30 units over the qualifying 12-month rolling average periods is presented in Figure 3-3 as a function of unit nameplate generating capacity.

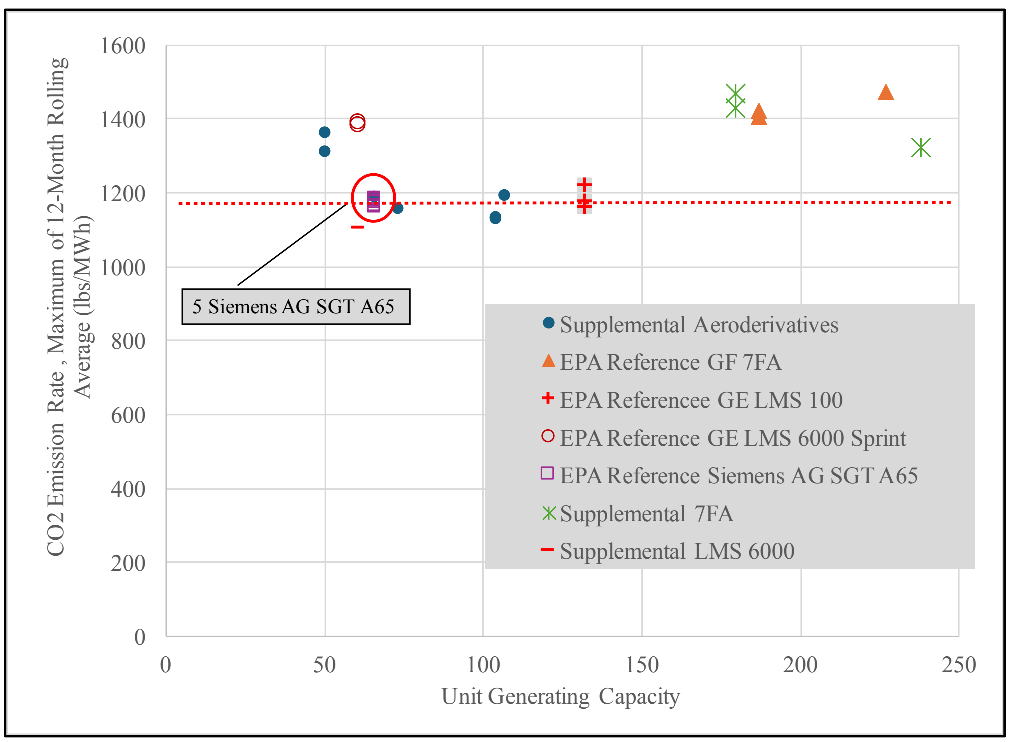

Figure 3-3. CO_2 Emissions Rate vs. Nameplate Capacity: 30 Simple Cycle Units Operating Between 20 and 40% Capacity Factor

The Figure 3-3 legend identifies data designated by EPA as references for the 2024 Phase 1 standard for simple cycle units operating at intermediate load. The legend also identifies the supplementary units introduced by this study. Notably, all of the units that can meet the intermediate load CO_2 performance standard are aeroderivative. Six of the 16 units cited by EPA are found to operate at or below the Phase 1 rate of 1,170 lbs/MWh (although 3 exceed by only 2 to 8 lbs/MWh). Three of the 14 supplemental units introduced by this study emit at less than the standard.

Combined Cycle

A total of 69 combined cycle generating units are identified from the EIA and EPA data and evaluated by this analysis. Of these, eight operated at an average 12-month capacity factor calculated over their operating years as less than 40%.

Figure 3-4 presents the maximum 12-month rolling average CO_2 emission rate (lbs/MWh) as a function of the nameplate generating capacity for units operating over 40% capacity factor. Of the 61 units in Figure 3-4, a total of 26 (42%) operated at CO_2 emissions rates that meet the 2024 Phase 1 GHG NSPS CO_2 emissions limit of 800 lbs/MWh. The average of all units in Figure 3-7 is 835 lbs/MWh. Notably, there are few combined cycle units that generate less than 250 MW capacity – and only one of a capacity of 100 MW or less. All of them emitted above the performance standard selected in the 2024 rule.

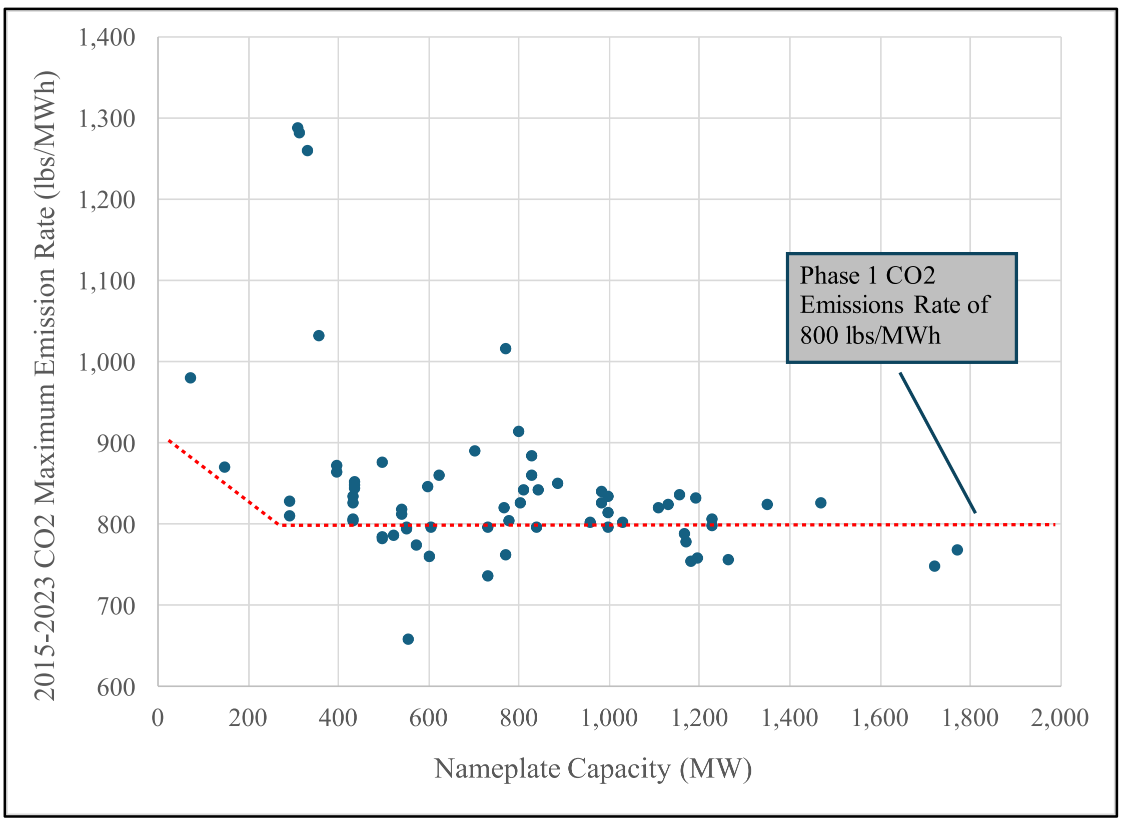

Figure 3-4. CO_2 Emissions Rate vs. Nameplate Capacity: Combined Cycle Units

Observations

The simple cycle and combined cycle databases used for this study identified more units than used by EPA and found more operating in the qualified range of capacity factors. The most notable difference is for simple cycle, in which 146 units identified as possible reference candidates, in contrast to 87 by EPA. Screening these units for capacity factor above 20%, the EPA database yielded 16 units while this study identified 30. This study also evaluated a greater number of combined cycle units – 69 compared to 59 cited by EPA. All but 8 units operated at a 12-month rolling average capacity factor of 40% and greater. The differences in the databases employed by EPA and this study appear mostly due to inclusion by the latter of numerous units that entered service in the last four years. Additional observations are offered as follows:

General

Although simple and combined cycle units exhibit very different capacity factors, their duty cycle is similar. For both categories of units, the duty cycle ranges from approximately 60% to more than 90%, showing that when in service these units tend to operate at high load.

Simple Cycle

CO_2 emission rates reported using AMD are generally higher than those calculated from suppliers' specifications, even when accounting for the real-world operating factors that negatively impact heat rate presented in Section 2. For approximately 65% of the units evaluated in this study, the maximum of the 12-month rolling average CO_2 emission rate exceeds the 1,170 lbs/MWh rate; no units exceeding approximately 175 MW range are able to comply with the 2024 Phase 1 intermediate-load emission standard. A description of how CO_2 emission rates are affected on design basis, focusing on the aeroderivative class versus F-Class, J- and H-Class, is addressed in Section 4. Only turbines entering service in the last 10 years are included in this analysis, thus long-term degradation of these units could not be determined from reported data. This uncertainty will likely further complicate meeting the standard.

Combined Cycle

Similar to simple cycle, CO_2 emission rates for combined cycle CTs reported using AMD are generally higher than those calculated from suppliers' specifications, including the mean and maximum margins presented in Section 2. For 26 of the 62 units operating at a 12-month average capacity factor of 40% or higher, the maximum of the 12-month rolling average CO_2 emission rate exceeds the 800 lbs/MWh rate. Consequently, 42% of 2015+ units do not achieve the output-based Phase I Base Load Subcategory CO_2 emission rate limit of 800 lbs/MWh. A description of how CO_2 emission rates are affected on design basis, focusing on the aeroderivative class versus F-Class, J- and H-Class, is addressed in Section 4.

Section 4. Critique of EPA Emission Rate Selection Methodology

EPA described in the final GHG rule the methodology by which the Phase 1 NSPS CO_2 emission performance standards are selected for both simple cycle (i.e., intermediate load units) and the combined cycle (i.e., base load units).[31] EPA's database employs 87 simple cycle and 59 combined cycle units; this study evaluated 146 simple cycle and 72 combined cycle units.[32]

The methodology for selecting these Phase 1 CO_2 emission rates is reviewed for both simple and combined cycle units.

Simple Cycle

EPA considered 16 units in their database to select a feasible CO_2 emission rate. Significantly, all were of aeroderivative design – with two exceptions, both GE 7FA turbines.

EPA determined the maximum 12-month average for each unit over the years of duty. For the 16 subject units, the CO_2 emission rate ranged from 1,156 to 1,470 lbs/MWh, with an average of 1,241 lbs/MWh. EPA acknowledges that most of the reference population is aeroderivative designs, with some units employing "intercooling" to lower compressor parasitic power, thereby increasing electricity generated and improving net heat rate. EPA also acknowledges that intercooling is not broadly applicable due to the need for a cooling tower and additional plant footprint.

Nonetheless, EPA in selecting a CO_2 emission rate of 1,170 lbs/MWh cites three reference aeroderivative turbine designs: (a) GE LMS100, (b) Siemens SGT-A65, and (c) GE LM6000. The relevant CO_2 emission rate data reported by EPA for these units show about half comply with the Phase 1 emission limit.[33] EPA did not identify any differences in design or operation that differentiated the noncompliant units from the compliant units.

This approach is deficient. First, within the three aeroderivative models that the EPA selected to base the standard on, eight out of a total of 16 units do not meet that standard. It is unclear why half of the turbines designated as references fail to standard – perhaps due to their operating history and other factors. These units' thermal efficiency is inherent to their design and cannot be

[31] 89 Fed. Reg. at 39,946-48.

[32] EPA's database does not include generating units that entered commercial service after 2020; no rational is cited. This analysis, being able to access data through 2024, could include units that operated in 2021-2023 and have adequate data to calculate at least 12 datapoints of 12-month rolling averages. Consequently, this study was able to utilize 78 additional units (69 simple cycle, 9 combined cycle).

[33] See EPA-HQ-OAR-2023-0072-0060_attachment_6, Worksheet "Chart Data", columns N, O, and Q.

changed. Some factors that can affect these units' 12-month rolling average CO_2 emission rate are out of their operators' control. These include site conditions and the associated ambient temperatures over a 12-month period, and hardware degradation between scheduled maintenance cycles. Most – if not all –- operators follow recommended maintenance practices, and thus have no control of the inherent degradation of the units and the associated compromise in thermal performance and whether such performance losses are recoverable between maintenance cycles. The operator has control of how to run the unit, but in practice market demand determines the dispatch and therefore the frequency of load changes, startup/shutdown events, etc.

EPA does not appear to have evaluated why half the aeroderivative CTs of the models referenced to set the performance standard did not meet that standard, and whether—even theoretically—these units could have done anything to meet the standard.

Second, EPA's reliance on only three specific aeroderivative models is even more problematic. Figure 4-1 presents the theoretical heat rate specified by the supplier (i.e., full-load, ISO conditions) for a sample of aeroderivative and intermediate capacity frame turbines broadly available in the U.S. Figure 4-1 calls out the three aeroderivative turbine designs designated by EPA as the basis of the 1,170 lb/MWh standard for intermediate-load simple-cycle turbines.

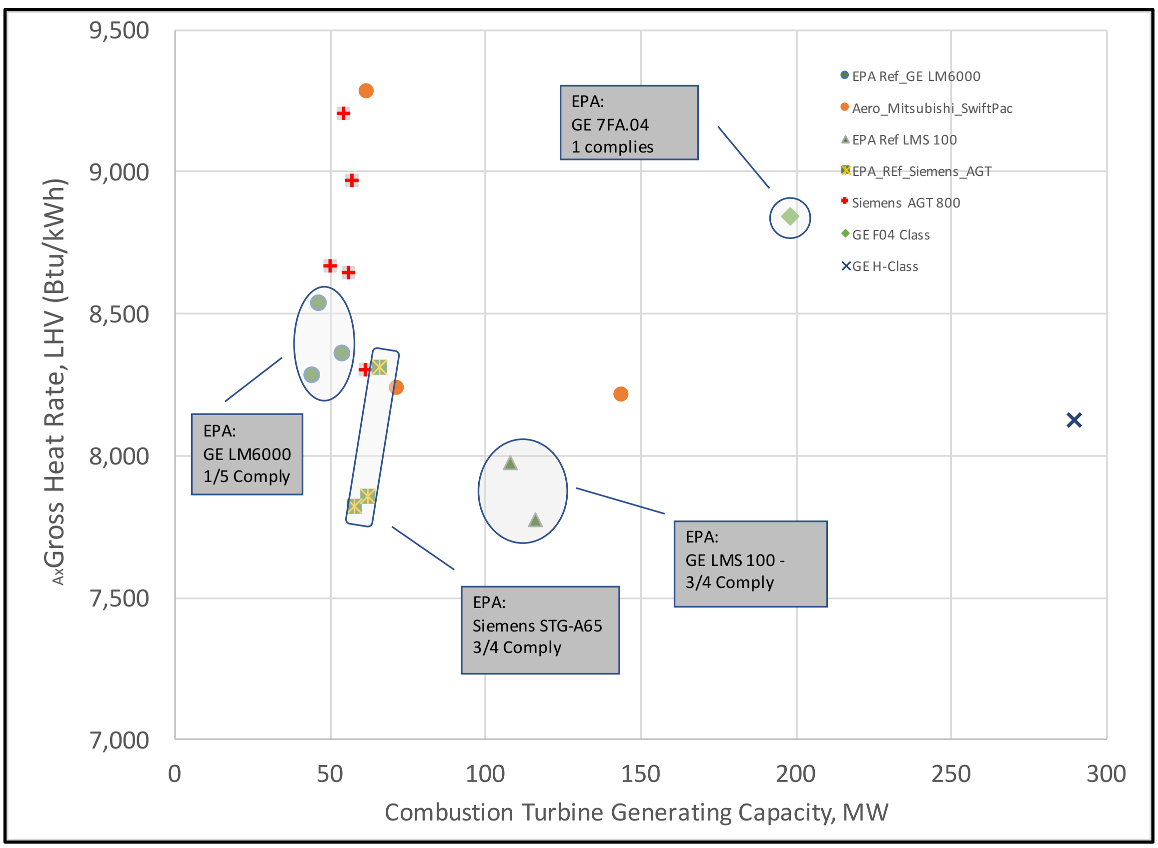

Figure 4-1. Combustion Turbines Suppliers' Specification of Gross Heat Rate: Aeroderivative and Frame Design of 50-300 MW

Putting aside the fact that half of the referenced model units did not meet the standard selected by EPA, any other CT model with an inherent (i.e., specification) heat rate exceeding that of the three aeroderivative models that EPA selected as the basis of the performance standard likely cannot meet the standard (at least not under operating duty and conditions similar to those experienced by the reference units). This includes many other aeroderivative models, as well as all E-Class and F-Class frame CTs, and all but the largest H-Class and J-Class frame CTs. All of these models are, effectively, limited to operating at low load (i.e., less than 20% capacity factor) because they cannot meet the intermediate load performance standard.

Figure 4-1 shows:

- EPA selected the two turbines with the lowest specified heat rate - the Siemens SGT-A65 and GE LMS100 to set the simple cycle CT CO_2 standard for units in the intermediate load subcategory. A third turbine – the GE LM6000 – presents similarly low specified heat rate in comparison to the remainder of the aeroderivative population. Almost without exception, the heat rates of all other aeroderivative-class turbines are higher. Establishing a 1,170 lb/MWh CO_2 emission rate standard effectively prohibits the use of aeroderivative-class turbine on the market for intermediate load duty, except for the three models favored by EPA.

- Many frame design turbines of 180-300 MW of generating capacity – representing likely candidates for simple-cycle applications in the U.S. – exhibit higher heat rates (and thus CO_2 emission rates). These turbines are desirable options for utilities due to their size, operating costs, and other operational factors. Several utilities have placed current orders for these units for several years out. EPA by setting the standard at 1,170 lb/MWh is effectively prohibiting the construction of most frame-design turbines with a capacity of 180-300 MW for intermediate load duty.

The aeroderivative design category does not represent the entire population of simple-cycle CTs. There are numerous differences in the design of aeroderivative compared to frame turbines – and not all the features of the former can be generalized or extrapolated to the latter. Most notably, aeroderivative turbines, due to their limited generating capacity and physical size, can utilize inlet compressors capable of delivering extremely high inlet pressures for combustion. This unique feature compromises EPA's near-exclusive use of this category as the reference case for simple cycle CO_2 emissions. The turbine inlet pressure is extremely important for this Brayton cycle – unlike the Rankine cycle deployed for fossil fuel-fired boilers and steam turbines, the simple cycle CT significantly benefits from high inlet pressure, elevating thermal efficiency. Inlet compressors for aeroderivative turbines elevate air pressure by a factor of 45-to-1 over ambient inlet pressure. Limits imposed by compressor suppliers on the maximum compressor blade "tip speed" prevent creating such high inlet pressures for frame turbines.[34] EPA did not identify high turbine inlet pressures as a component of BSER; clearly, this design feature influenced the choice of "highly efficient" units. However, as previously noted, the larger frame

[34] Compressor blade maximum tip speed is determined by the material strength and aerodynamic limits, which restricts rotational speed and the dimensions – and thus the power output - of the turbine. See *Gas Turbine Design Philosophy*, GE Power Generation, GE-3434D.

turbines requiring higher blade tip speed prevent this performance-enhanced feature from being applied on frame units.

Figure 4-2 compares the turbine inlet pressure ratio for aeroderivative and frame design turbines as a function of heat throughput. In the context of this discussion, the turbine inlet pressure ratio is the ratio of the air pressure delivered to the turbine combustor, relative to ambient air. This critical ratio for aeroderivative turbines (blue data and trend line) approaches 45, while for frame turbines this metric is limited to 25 (orange data and trend line).

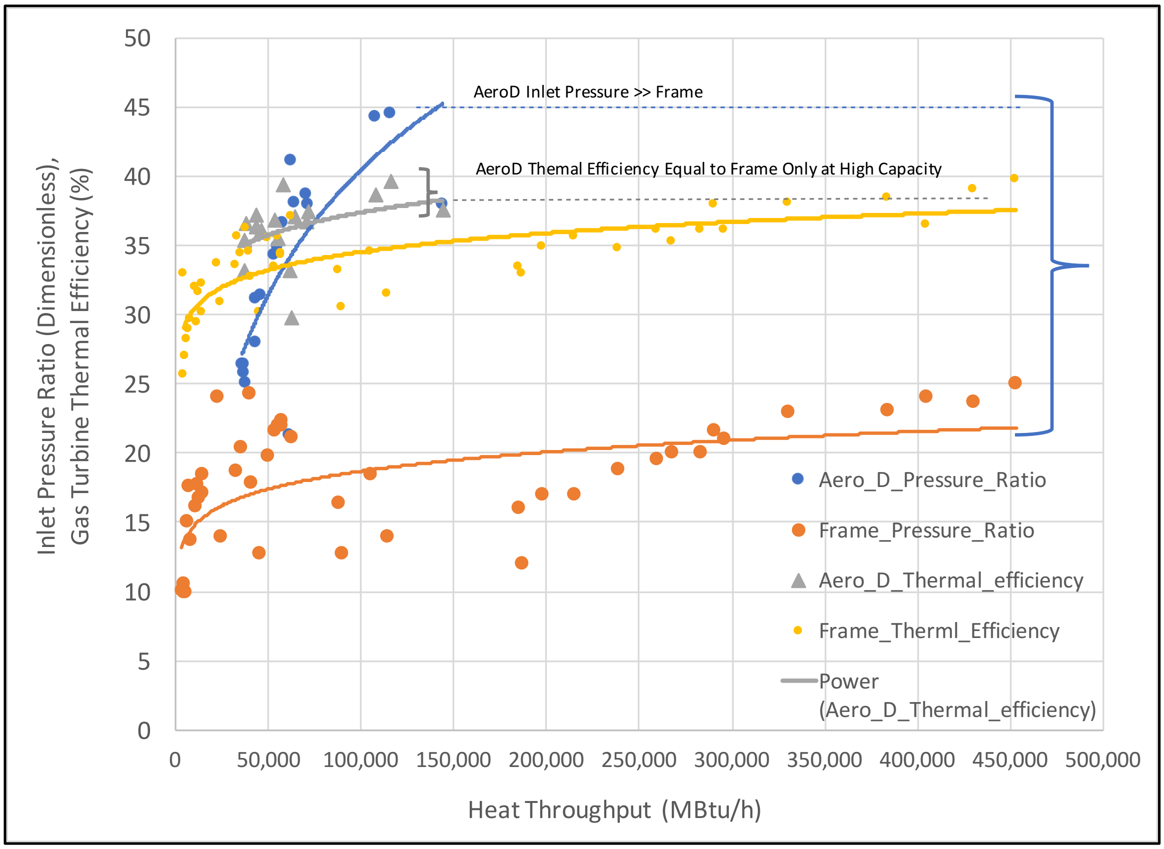

Figure 4-2. Combustion Turbine Inlet Pressure Ratio, Thermal Efficiency: Aeroderivative, Frame Designs

Figure 4-2 also shows the suppliers specified (inherent) thermal efficiency for each category of turbines. The figure shows that aeroderivative designs (gray data and trend line) enjoy higher thermal efficiency than frame designs (yellow data and trend line). Figure 4-2 also shows that the turbine inlet pressure ratio for frame turbines is well below that of aeroderivative – in many cases by half. As a result, the specified thermal efficiency of frame turbines in this category is less than aeroderivative by 2-4 percentage points. H- and J-Class units exhibit thermal efficiency approaching 40% – but only for these largest capacity turbines.

In summary, EPA's methodology of basing simple cycle CO_2 emission rates on aeroderivative turbines is flawed, as it allows the high inlet turbine pressure ratio achievable only on these smaller generating capacity units to drive the theoretical thermal efficiency of the CT and, therefore, its CO_2 emissions rate. Within the aeroderivative category, EPA selected among the most efficient units on which to base the standard. However, operating data show that the standard is not universally attained (in fact, it is attained by half of the aeroderivative population). EPA did not account for differences in units that could – and those that could not - attain the Phase 1 Intermediate Load limit.

Combined Cycle

EPA reviewed the emission rate data from 59 units in their database to select Phase 1 CO_2 emission standards for combined cycle units. EPA recognized the combined cycle CO_2 emission rate is affected by several design decisions, such as the arrangement of the combustion turbine, the HRSG, and the steam turbine, and means for cooling (wet or dry tower). Table A-2 in the Appendix presents examples of various arrangements – in addition to the most common arrangement of one combustion turbine/HRSG aligned with one steam turbine (1 x 1), the arrangement of two combustion turbines and HRSGs and one steam turbine (2 x 1) can generate greater power and extract higher thermal efficiency. This combined cycle arrangement is important in evaluating CO_2 emission rate.[35] EPA also recognized the operating point on the load curve – either near full nameplate capacity or at minimum load – drives the CO_2 rate.

EPA evaluated data from the 59 units operating since 2015 and determined the maximum 12-month rolling average of the population. The EPA reports 12-month rolling CO_2 emission rates ranging from 720 to 920 lbs/MWh, with an average of 810 lbs/MWh. EPA recognized that low-emitting units had features not applicable to the broad population of units, such as the Okeechobee Clean Energy Facility and the Dresden plant. These units' CO_2 emission rate averaged 770 lbs/MWh, enabled by a 2 x 1 arrangement and wet mechanical cooling towers, both of which reduce heat rate and CO_2 emission rate. Further, Okeechobee operates primarily at high load which further enables low CO_2 emission rates over a long averaging period (such as 12 months). Since most combined cycle units will likely be required to load follow during their lifetime, a limit based on high load operation is not broadly applicable to all operating cycles for most units covered by the NSPS.

Still, EPA singled out the Dresden plant as a reference unit, upon which EPA ultimately based its Phase 1 standard of 800 lb CO_2/MWh (for units larger than 2,000 MBtu/h):

> *.....the EPA has determined that the Dresden combined cycle EGU demonstrates that an emissions rate of 800 lb CO2/MWh-gross is achievable for all new large combined cycle EGUs with an acceptable compliance margin. Therefore, the EPA is finalizing a phase 1 standard of performance of 800 lb CO2/MWh-gross for large base load combustion turbines (i.e., those with a base load rating heat input greater than 2,000 MMBtu/h) based on the BSER of highly efficient combined cycle technology.*[36]

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[35] The 2 x1 arrangement increases thermal efficiency but is also enhances operating flexibility by providing for online power generation while one combustion turbine undergoes maintenance and repair. Operating in this mode reduces thermal efficiency and increases output-based CO_2 emission rate. The Subpart TTTTa baseload emission limit should not prevent operation in this mode.
[36] 89 Fed. Reg. at 39,947.

The Dresden Plant is an unusual choice as a reference. The two GE 7FA combustion turbines precede two Voght high pressure HRSGs, and a single GE steam turbine – a 2 x 1 array. The original design F-Class turbines have been upgraded with GE Advanced Gas Path hardware.[37] This hardware is reported by GE to increase the combustion turbine thermal efficiency by 1.2% with a further potential increase in steam side thermal efficiency pending higher turbine effluent gas flow and higher gas temperature.[38] Also, the facility employs wet mechanical cooling towers, which lower heat rate and CO_2 emission rate. Although the use of wet cooling towers is not prohibited, their water use can complicate permitting in many areas.

Using the 59 units, EPA developed a database reflecting the conventional 1x1 arrangement and dry cooling tower by "adjusting" CO_2 emission from units with multi-shaft arrangement (increasing CO_2 by 1%) and wet cooling (increasing CO_2 by 1.4%).[39] EPA also recognized that operation at low load elevates CO_2 emission rate. Consequently, EPA used historical data from each unit describing CO_2 emission rate as a function of load to project any increase in emission at 40% capacity. Figure 4-3 presents data from the Dresden Plant used for this purpose.[40]

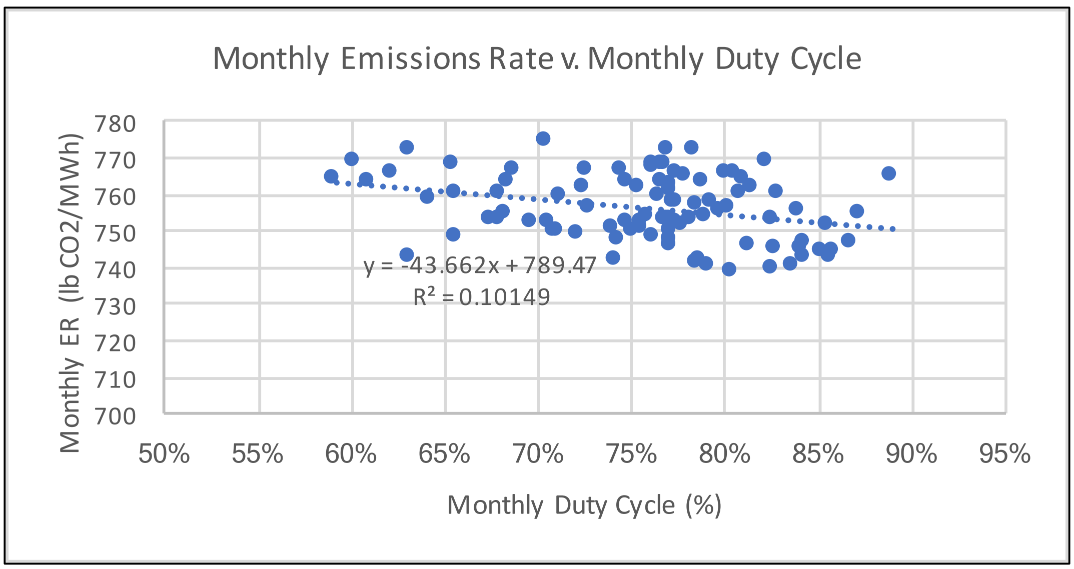

Figure 4-3. Example of Data Evaluation, Correlation Used for Dresden Plant Evaluation

There is no analysis in the 2024 rulemaking of whether the Dresden CO_2 emission performance is representative of what combined cycle units generally can achieve. First, Dresden is an F-Class based combined-cycle unit. It is not representative of smaller, E-Class and aeroderivative-based combined cycle units. In addition, the Dresden CO_2 data is not representative of the bulk

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[37] AEP, personal communication, July, 2025.

[38] https://www.ge.com/news/press-releases/ges-advanced-gas-path-upgrades-generate-775-million-total-customer-value-annually

[39] CO_2 emissions from units with multi-shaft arrangements was elevated by 1% to translate to a 1 x 1 arrangement, and CO_2 from units with wet cooling tower was increased by 1.4% to account for a dry cooling tower.

[40] Adjustment factors to account low load (40% generating capacity) operation are derived for reference units in EPA_HQ-OAR-2023-0072-0060_attachment_4. See Worksheet Dresden 1A.

of operating F-Class and larger CT-based combined cycle units. This is evident from examining Figure 2-2, which presents the calculated CO_2 emission rate based on the suppliers' specification, and a "mean" adjustment of 12.5%. The CO_2 emissions in this figure for a 602-MW F-class combined cycle in 2 x 1 configuration is shown as 850 lbs/MWh. It should be noted that the value of 24% adjustment is implied by Figure 2-4 for the F-Class based population, approximating not the "mean" adjustment but the maximum. Also, Figure 2-4 shows a relatively high standard deviation of 171 lbs/MWh, implying approximately 6 units can emit at 751 lbs/MWh or less. This means the Dresden data resides in the lowest statistical cohort of F-Class combined cycle data.

Figure 4-4 depicts the data previously presented in Figure 3-4, but plotted as a function of capacity factor. The Dresden CO_2 emission rate of 771 lbs/MWh is called out on the figure for an annual capacity factor that averages 70% for the relevant operating years. As Figure 4-4 shows, there are approximately 10 units in the combined cycle population that emit CO_2 at a rate lower than Dresden; the vast majority of units in the database emit at higher rates. The increment provided by elevating the rate to 800 lbs/MWh does not significantly improve the margin for compliance for these units.

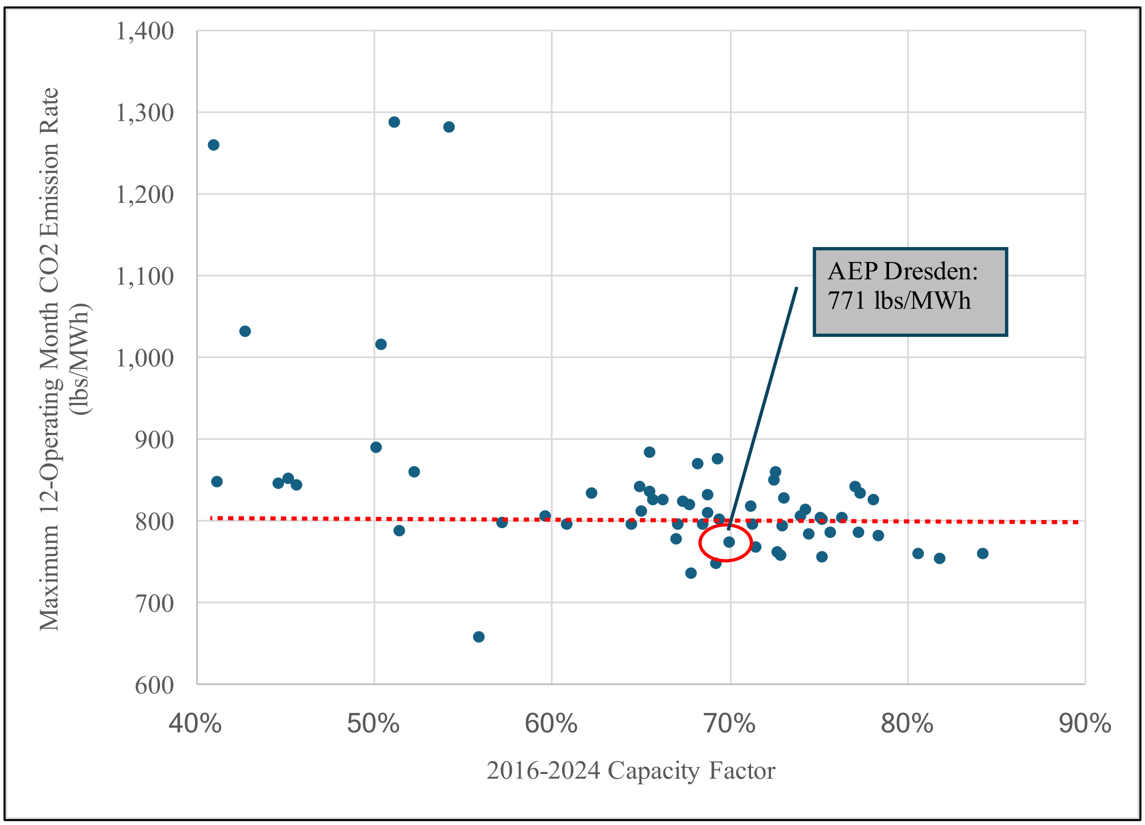

Figure 4-4. CO_2 Emissions from the Combined Cycle Population: Role of Dresden

EPA does not offer an analysis into the 2024 record as to why they determined any new combined-cycle unit ought to be able to achieve the CO_2 emission rate achieved by Dresden. As this study emphasizes, the 12-month rolling average efficiency (and, therefore, CO_2 emissions rate) of a combustion turbine is affected not just by the inherent efficiency of the unit, but also by operating conditions (i.e., elevation; average ambient temperature; unavoidable degradation; air inlet fouling; and condenser conditions) as well as operating duty (not just average capacity factor, but more importantly average duty factor; frequency of startup and shutdown; frequency and rate of load changes; etc.). Operating conditions are outside the control of the operator entirely. Operating duty is theoretically subject to operator control, though it is largely dictated by grid demand and constraints. EPA selected Dresden as representative, without analysis of whether Dresden itself would be able to meet the CO_2 emission rate EPA selected were Dresden located at a higher altitude, or operated at higher ambient temperature, or at a different duty (within the base load category). Nor did EPA analyze why the majority of operating combined cycle units in the database emitted CO_2 at a higher rate than Dresden. Without these analyses, there is no basis for concluding that any new unit should be able to meet the CO_2 rate that Dresden achieved under its own operating conditions and duty.

It is also clear that no combined-cycle unit with a base load rating less than 2,000 MBtu/h in the available database achieves the sliding-scale standard of 800 to 900 lb CO_2/MWh).

Conclusions

Simple Cycle. The 2024 Phase 1 output-based CO_2 emission performance standard for intermediate load turbines of 1,170 lbs/MWh for simple-cycle CTs operating at intermediate load is derived almost exclusively from aeroderivative design turbines, for which inlet turbine pressure ratio – among other factors unique to aeroderivative design – cannot be replicated on frame units. The ability to deliver inlet air pressure at a ratio of 45-to-1 (compared to ambient) that cannot be replicated on large frame engines due to a design limitation of compressors (per maximum blade tip speed). Such aeroderivative units are not representative of the larger frame-type units that could be deployed. Further, the three specific reference units represent an extreme edge of the thermal performance envelope for all simple-cycle CTs. Even within the aeroderivative models selected by EPA, not all units demonstrate compliance with the standard.

Combined Cycle. The combined cycle's 2024 Phase 1 CO_2 emission rate of 800 lbs/MWh (for units larger than 2,000 MBtu/h) is based on projection of thermal performance of a unit that is not representative of the turbine population. Without an analysis of why the vast majority of combined-cycle CTs in the database never met the selected standard, EPA cannot conclude any new unit should be able to meet the usually low CO_2 emission rate achieved by an outlier unit.

Section 5. Critique of Cost Evaluation: Simple, Combined Cycle LCOE Equivalency

The EPA's decision to select a 40% capacity factor as the threshold for the base load category is derived from a cost evaluation of the levelized cost of electricity (LCOE) for simple and combined cycle units.[41] In effect, EPA set the emissions standard for the base load subcategory (800-900 lb/MWh) to be achievable by combined-cycle CTs only; as a result, simple-cycle CTs, under the 2024 rule, are prohibited from operating at more than 40% capacity factor.

Section 5 critiques EPA's evaluation on several accounts. First, the analysis requires comparing performance and cost of simple and combined cycle units of identical generating capacity – for which a source does not exist in the available literature.[42] Thus, EPA elects to "create" four new reference cases, requiring up to four "adjustments" or "extrapolations" each of which introduces error. EPA does not account for these errors and the resulting uncertainty in its analysis. Second, for each of the four new reference cases, EPA selects a narrow range of input conditions that determine results (i.e. unit lifetime and natural gas price) which may not reflect future applications. Small changes to these inputs can substantially alter the results.

This section reviews EPA methodology and proposes an alternative approach. Moreover, regardless of the approach, small changes in assumptions yield significant changes in the LCOE analysis. This suggests that the deterministic LCOE analysis that EPA used to set the 40% capacity factor threshold for base load is not supported.

EPA Methodology

An overarching observation is that generating plant cost estimates are constantly evolving in response to the market. Capital cost estimates for both simple and combined cycle units have escalated in recent years, and may continue to do so pending supply chain issues. Generalized studies from entities such as the National Energy Technology Laboratory (NETL) and the Energy Information Administration (EIA) may not always accurately reflect the current economic climate, much less the economic climate in the next decade and beyond.

EPA references an NETL report that develops cost and performance data for a variety of natural gas-fired generating units.[43] These reference cases range from 50 MW aeroderivative turbines to several variants of combined cycle units with F-Class and H-Class turbines. The relevant

[41] Efficient Generation: Combustion Turbine Electric Generating Units Technical Support Document, Docket ID No. EPA-HQ-OAR—2023-0072, April 2024. At p. 31. Hereafter 2024 Efficient Generation TSD.
[42] Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, National Energy Technology Laboratory, May 2023.
[43] Ibid.

comparison is the LCOE for simple cycle versus combined cycle units at the same generating capacity.

The four generating capacities EPA selected for comparison are as follows:

- 100 MW. NETL provides the simple cycle design, with EPA creating the combined cycle version by "scaling" data from other sources.

- 50 MW. NETL results enable the extraction of a nominal 50 MW simple cycle design from the reference case. The combined cycle case is created by "scaling" cost and performance from reference units to extremely small scale.

- F-Class (375 MW). The NETL report provides the combined cycle reference case; the cost and performance for the CT in simple cycle is scaled.

- H-Class (560 MW). NETL provides the H-Class combined cycle reference; the cost and performance for the CT in simple cycle is scaled.

These four comparisons are developed as follows:

Aeroderivative Cases

The steps EPA cites to create 50 MW and 100 MW combined cycle units are as follows:

<u>Define New HRSG/Steam Turbine Cost</u>. EPA uses conventional "power-scaling scaling" laws to adopt cost for steam components from F-Class and H-Class units to the 50 and 100 MW capacity. The use of this method to scale cost by a factor of ten violates DOE/NETL standard practice, as advised in the *2013 Scaling Quality Guidelines* that power-law exponents be used with caution. [44] Specifically, DOE/NETL caution that "…..*there is a large percentage difference between the scaling parameters. This is particularly true for the major equipment items.* The use of this methodology to scale by more than a factor of 10 is beyond the conventional range.

<u>Implement Cost "Deducts" to Account for Scope Differences</u>. The HRSG and steam turbine costs for the F- and H-Class units exhibit features not typical of small aeroderivative-based combined cycle. Thus, capital costs must be reduced, as an auxiliary boiler (2.2%) is not required for fast-start, and the lower steam pressure HRSG and steam turbine (3.9% reduction) are also considered. A further cost "deduct" of 40% for the HRSG was adopted to account for lower heat throughput, as these smaller units use intercooling which reduces the heat removed.

To estimate fixed and variable operating and maintenance costs, EPA extrapolated those costs developed for the larger F-Class and H-Class units.

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[44] Quality Guidelines for Energy Systems Studies, Capital Cost Scaling Methodology, DOE/NETL DOE/NETL DOE/NETL-341/013113, January 2013. At 18.

Each of these adjustments can introduce an error of 10% or more. Perhaps most significant is the use of a power-scaling law to translate capital cost from one generating capacity to another. There are two flaws in EPA's application. First, EPA uses the power-scaling law well outside the advised limit. The cost for steam-side equipment is scaled from the 375 MW F-class or 560 MW H-class units to 50 and 100 MW aeroderivative units. As noted in the 2013 DOE/NETL Scaling Guideline, the use of conventional power-law scaling methodology introduces significant risk when there is a large difference between the reference and the target capacity.[45]

Second, the scaling "exponent" of 0.6 represents conventional practice and does not necessarily represent the values relevant for thick-walled, high-pressure components.[46] The technical literature on cost scaling describes a wide range of exponents depending on equipment type. Specifically, a classic engineering treatment of cost evaluation states that most scaling exponents can range from 0.27 to 1;[47] and many "cluster" around 0.6 and it is convenient in certain cost-estimating actions to adopt "six-tenths" for the power law. The selection of a scaling exponent per this criterion is not a rigorous basis for a cost study with national policy implications. Regarding the use of the "sixth-tenth" exponent, Peters and Timmerhaus note:

> *the application of the 0.6 rule-of-thumb for most purchased equipment is an oversimplification of valuable cost concept since the actual values of the cost capacity factor vary from less than 0.2 to greater than 1.0 as shown in Table 5. Because of this, the 0.6 factor should only be used in absence of other information*.[48]

For power generation, the Electric Power Research Institute (EPRI) Technical Assessment Guide recommends scaling the cost of power generation equipment by using exponents that vary from 0.24 to 0.28.[49] Exponents of this value are appropriate for scaling the cost of entire power-generating facilities – including foundations, high-pressure steam components, and precision equipment such as steam turbines.

A major cost adjustment for which little basis is presented is the 40% reduction in HRSG costs due to the use of inter-stage cooling.

As an aside, comparison of 50 MW and 100 MW units is likely not relevant. As EPA explains, an owner of a 50 or 100 MW simple cycle will utilize this unit to meet different mandates in terms of ramp rate and would not consider a 100 MW combined cycle unit.

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[45] Ibid. At 18. There are limitations on the ranges that can accurately be addressed by the scaling approach. There can be step changes in pricing at certain equipment sizes that may not be captured by the scaling exponents. Care should be taken in applying the scaling factors when there is a large percentage difference between the scaling parameters. This is particularly true for the major equipment items.
[46] EPA notes "The rule of six-tenths is a generic approach to estimating economies of scale". See 2024 TSD, footnote 110.
[47] *Plant Design and Economics for Chemical Engineers, Fourth Edition*, Peters M.S. and Timmerhaus K.D. McGraw Hill International Editions, Chemical and Petroleum Engineering, 1991. See page 170, Table 5.
[48] Ibid. Page 169.
[49] EPRI Technical Assessment Guide, Electricity Supply – 1993, EPRI TR-102276-V1R7, Volume 1: Rev. 7. See page 8-11.

F-, H-Class Comparison

The NETL cases of CC1A-F and CC1A-H are combined cycle reference cases at 375 MW and 560 MW respectively. EPA extracts the simple cycle generating unit cost and performance and adjusts it to a comparable generating capacity. EPA employed the following steps.

Adjustment 1. "Subtract" the cost of components dedicated to the steam cycle and associated hardware. The result is a simple cycle cost for F- or H-Class unit.

Adjustment 2. EPA utilizes steam side costs from a 2009 World Bank Study, which projects steam cycle equipment costs derived from 1996 to 2003, to refine the combined cycle costs of F-Class and H-Class.[50] The reference chart on page 32 of the Technical Support Document[51] could not be identified in the source document. This step could introduce significant error.

Adjustment 3. EPA estimated fixed cost and the fixed and variable operating and maintenance costs for the new combined cycle unit by extrapolating the NETL reference cases by relative heat inputs between the NETL and new reference cases.

Every one of these adjustments and estimates relies on assumptions that can substantially influence the results, as well as engender a fair amount of uncertainty.[52] EPA then selected a 30-year unit lifetime and natural gas price of $4.43/MBtu to determine LCOE.

The projected capital cost for these new reference cases contains numerous uncertainties which should be considered in the significance of the conclusions. Every one of these adjustments and estimates relies on assumptions that can influence the results substantially and promote uncertainty. Table 5-1, extracted from the TSD, shows that – particularly at a 40% capacity factor – the difference in cost range is from "zero" to 2%, which is decidedly small in the context of the assumptions and adjustments.

[50] *Study of Equipment Prices in the Power Sector*, Energy Sector Management Assistance Program, Technical Paper 122/09, January 2009. Hereafter 2009 Equipment Prices Study

[51] *Efficient Generation: Combustion Turbine Electric Generating Units Technical Support Document*, Docket ID No. EPA-HQ-OAR-2023-0072, April 2024.

[52] It should be noted the explanation of the steps executed by EPA as described by the *2024 Efficient Generation TSD* are not clear and do not portray an understanding of the EPA's actions. Specifically, the description presented does not describe how data from the *2009 Equipment Prices Study* are used in lieu of the cost available describing steam side components as presented in the F-Class and H-Class cases of the 2023 NETL study.

Table 5-1. Comparison of LCOE: EPA Manufactured Reference Cases

	Steady State LCOE ($/MWh)							
Capacity Factor (%)	F-Class Combined Cycle	F-Class Simple Cycle	H-Class Combined Cycle	H-Class Simple Cycle	100 MW Aeroderivative Combined Cycle	100 MW Aeroderivative Simple Cycle	50 MW Aeroderivative Combined Cycle	50 MW Aeroderivative Simple Cycle
5%	308	237	268	205	428	380	506	448
10%	166	136	146	119	229	207	267	242
20%	96	86	85	76	130	121	147	139
30%	72	69	65	62	96	92	107	104
40%	60	61	54	55	80	78	87	87
50%	53	56	48	50	70	69	75	77
60%	48	53	44	47	63	64	67	70
70%	45	50	41	45	58	59	62	65
80%	43	49	39	44	55	56	57	61

Alternative Approach

A 2024 EIA analysis[53] is a better reference study for this purpose. This 2024 study contains one reference case that can be used without adjustment; only one "case" needs to be created by extrapolating costs over a small range. EPA cites this 2024 EIA work but does not utilize it.

This EIA work (conducted by Sargent & Lundy) developed capital and operating costs for two reference cases employing an H-Class combustion turbine. A simple cycle design generating 419 MW at a heat rate of 8,873 Btu/kWh is represented by Case 4, with a Case 6 combined cycle generating 627 MW at a heat rate of 6,222 Btu/kWh (comprised of a 453 MW combustion turbine and 192 MW steam turbine). The Case 6 combined cycle design can be extrapolated from 627 MW to the Case 4 capacity of 419 MW, within the advised application of scaling laws.

The comparison of simple versus combined cycle units at approximately 450 MW reflects the present commercial marketplace. For example, among the combined cycle commercial offerings in Appendix A Tables A-1 and A-2 are Siemens simple and combined cycle units employing the SGT6-8000HL combustion turbine at comparable generating capacities. GE offers a simple and combined cycle unit using the GE HA.02 combustion turbine, generating 384 MW in simple cycle and 573 MW in combined cycle. These commercial offerings are well reflected by the reference cases cited by this study.

Table 5-2 presents two cases relevant for this analysis at 419 MW. The cost and performance characteristics for the EIA H-Class Case 4 and the adjusted Case 6 to match the 419 MW output are summarized. Capital costs are scaled as are fixed and variable O&M costs.

[53] Energy Information Agency, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, January 2024.

Table 5-2. Referenced Cases per Energy Information Administration Performance, Cost

Variable	**Case 4: SC, H-Class**	**Case 6: CC, H-Class**	**Case 6 Adjusted per Output**
Capacity, MW	419	627	419
Capital, $/kW)	838	921	
Scaling exponent: 0.6			1,082
Scaling exponent: 0.5			1,127
Heat Rate (Btu/kWh)	9142	6226	6226
Fixed O&M, $/kW-yr	6.87	16.46	20.14
Var O&M ($/MWh)	1.24	3.33	4.07

Table 5-2 demonstrates the uncertainty inherent in the input assumptions, by reporting capital scaled by using both EPA's selection a "0.6" exponent, and a value of "0.5" – a difference that reflects scaling for high pressure, thick walled components. Notably, the use of "0.5" versus "0.6" lowers the capital cost of the combined cycle from $1,127/kW to $1,082/kW – a 4% difference, which influences the outcome.

Figure 5-1 presents results of calculations reporting the LCOE (as $/MWh) from the EIA study. Three options are addressed: the 419 MW simple cycle (Case 4), the 627 MW combined cycle (Case 6), and an extrapolated "new" combined cycle unit of 419 MW combined cycle (extrapolated Case 6). The LCOE is presented as a function of capacity factor. Figure 5-1 results are presented for generating capacity, combined cycle capital cost, and natural gas price that differ very slightly from those employed by EPA. Specifically, these are slightly shorter lifetime (25 years), higher capital cost (resulting from the use of a 0.5 scaling factor), and a natural gas price ($4.00/MBtu). These represent small changes from EPA's input and are at least equally representative of future conditions.

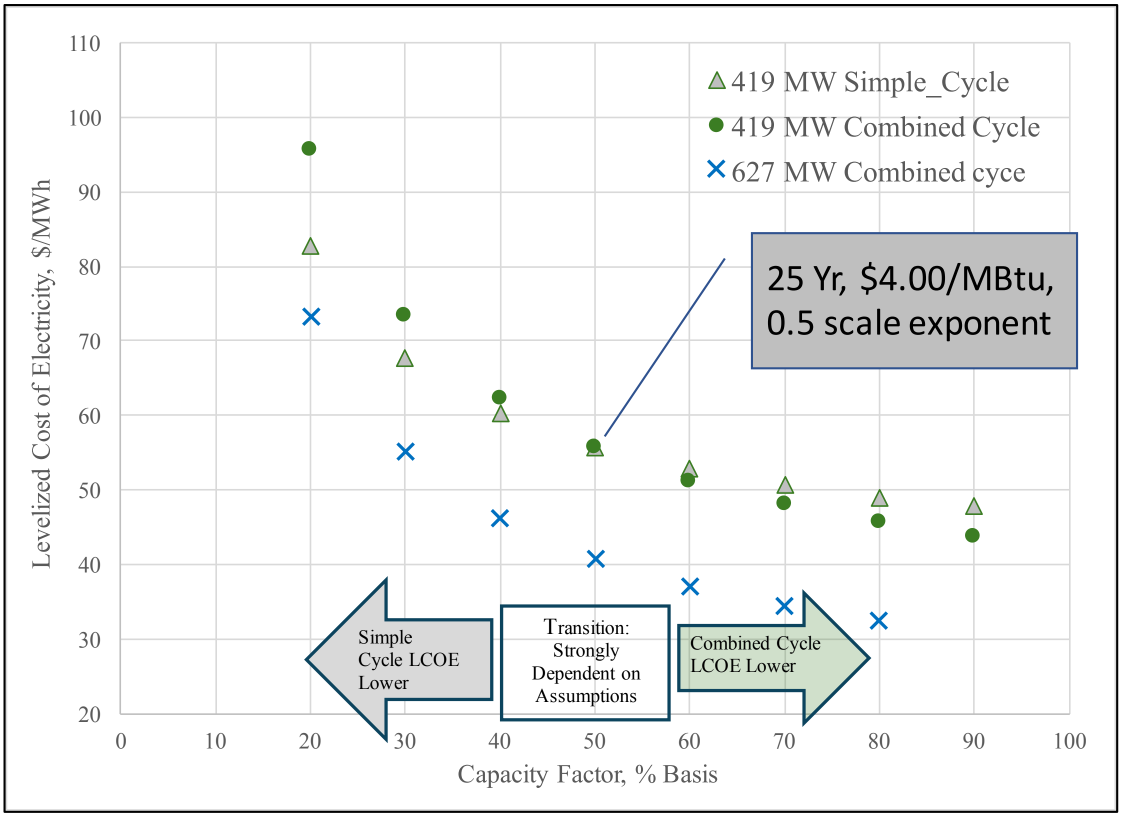

Figure 5-1. LCOE Equivalent per Adjusted EIA Analysis

Figure 5-1 shows that, using these factors, the LCOE from a simple cycle remains lower than that of a combined cycle up to a capacity factor of 52%.[54] The LCOE from the 627 MW (Case 6) combined cycle unit is significantly lower for the same 25-year lifetime and $4.00/MBtu natural gas costs, enabled by strong economies of scale.

Conclusions

EPA's conclusion that at 40% capacity factor the LCOE of a future combined cycle unit equates to that of simple cycle is highly uncertain, and based on assumptions that may not reflect future duty. EPA's use of an NETL study and the need to implement up to 4 "adjustments" to create new reference cases can introduce significant error, and bias the results to favor the combined cycle.

An alternative cost evaluation using a 2024 EIA study requires minor scaling of cost to derive comparable reference cases. The use of these EIA-derived reference cases and a 25-year unit life, natural gas cost of $4.00/MBtu, and a "scaling" exponent in agreement with literature for high-pressure components shows simple cycle LCOE lower than combined cycle up to 52% capacity factor.

[54] Exactly replicating EPA's inputs of a 30-year lifetime, natural gas cost of $4.43/MBtu, and the "default" scaling exponent shows simple cycle LCOE less than combined at 52% capacity factor.

Due to uncertainties introduced by EPA's methodology and the selection of key input values, using 40% capacity factor to define the base load segment of generation is not justified. The evaluation of simple cycle versus combined cycle LCOE described in this report highlights flaws in EPA's analysis. The methodology proposed by this report, not requiring the large number of extrapolations, is as reasonable as EPA's and justifiably supports a 52% threshold. Moreover, NSPS is forever. The economics of producing electricity could change. It may not be appropriate for EPA to mandate that simple-cycle CTs can never be used for base load operations (at whatever level EPA selects for this load subcategory).

Appendix A. Reference Supplier Combustion Turbine Data

Table A-1. Simple Cycle Units

	Turbine Supplier/Model	Output (MW)	Heat rate (Btu/kWh, LHV)
J-Class			
Mitsubishi	M501JAC	453	7755
H-Class			
Ansaldo	GT36	563	7935
Siemens	SGT6-8000HL	440	7898
GE	7HA.03	430	7884
GE	7HA.02	384	8009
Siemens	SGT6-8000H	328	8530
GE	7HA.01	290	8120
G-Class			
Mitsubishi	M501GAC	283	8531
F-Class			
Ansaldo	GT26	370	8322
Siemens	SGT6-5000F	260	8530
GE	7F.05	239	8871
GE	7F.04	201	8873
GE	6F.03	88	9277
E-Class			
Siemens	SGT6-2000E	119	9611
GE	7E.03	90	10107
Mitsubishi	M501DA	113	8930
Aeroderivative			
Mitsubishi	FT4000SwiftPac 140	144	8209
GE	LMS100 PA+	117	7702
Mitsubishi	FT4000SwiftPac 70	71	8232
Mitsubishi	FT4000SwiftPac 60	62	9281
GE	LM6000 DLE PF+	54	8277
GE	LM6000 SAC PG	54	8666

Table A-2. Combined Cycle Units

Class			Array	Output (MW)	Heat Rate (Btu/kWh, LHV)
J-Class	Mitsubishi	M501JAC	1 x 1	664	5332
			2 x 1	1332	5315
H-Class	Ansaldo	GT36	1 x 1	800	5451
			2 x 1	1605	5433
	Siemens	SGT6-8000HL		440	5416
	GE	7HA.03	1x1	648	5342
			2x1	1298	5332
		7HA.02	1 x 1	573	5381
			2 x 1	1148	5365
	Siemens	SGT6-8000H	1x1	465	5530
			2x1	960	5530
	GE	7HA.01	1x1	438	5481
			2x1	880	5453
G-Class	Mitsubishi	M501GAC	1x1	427	5640
			2x1	856	5652
F-Class	Ansaldo	GT26	1 x 1	540	5594
			2 x 1	1083	5575
	Siemens	SGT6-5000F	1 x 1	387	5725
			2 x 1	775	5715
	GE	7F.05	1 x 1	379	5667
			2 x 1	762	5640
		7F.04	1 x 1	309	5716
			2 x 1	602	5675
		6F.03	1x1	135	5998
			2x1	272	5994
E-Class	Siemens	SGT6-2000E	1x1	178	6354
			2x1	356	6354
	GE	7E.03	1x1	140	6514
			2x1	283	6454
	Mitsubishi	M501DA	1 x 1	167.4	6193
			2 x 1	336.2	6083
Aero-D	Mitsubishi	FT4000SwiftPac 140	1 x 1	180	6682
	GE	LMS100 PA+	1 x 1	137	6567
			2 x 1	247	6555
	Mitsubishi	FT4000SwiftPac 70	1 x 1	89.3	6734
	Mitsubishi	FT4000SwiftPac 60	2 x 1	85	6878
	GE	LM6000 DLE PF+	1 x 1	54	8277
	GE	LM6000 SAC PG	1 x 1	54	8666

Appendix B. Units Not in EPA Study

Table B-1. Units Excluded from EPA Data Base

plant_id	plant_name	Units	State	Cycle	In Service Date
3	Barry	1	AL	C	2023
56	Lowman Energy Center	1	AL	C	2023
136	Seminole (FL)	1	FL	C	2023
6061	R D Morrow	1	MS	C	2023
55460	Indeck Niles Energy Center	1	MI	C	2022
57185	Cricket Valley Energy	3	NY	C	2020
58001	Panda Temple Power Station	1	TX	C	2015
58478	LEPA Unit No. 1	1	LA	C	2016
59220	Wildcat Point Generation Facility	1	MD	C	2018
60356	South Field Energy	2	OH	C	2021
60903	Salem Harbor Power Development	2	MA	C	2018
60925	Montgomery County	1	TX	C	2021
60927	Lake Charles Power	1	LA	C	2020
61028	Hickory Run Energy Station	1	PA	C	2020
62192	Blue Water Energy Center	1	MI	C	2022
47	Colbert	3	AL	S	2023
141	Agua Fria	2	AZ	S	2022
492	South Plant	5	CO	S	2023
641	Gulf Clean Energy Center	4	FL	S	2021
1378	Paradise	3	KY	S	2023
3456	Newman	1	TX	S	2023
10350	Greenleaf 1	1	CA	S	2022
55129	Desert Basin	2	AZ	S	2022
56298	Roseville Energy Park	2	CA	S	2022
56350	Colorado Bend Energy Center	2	TX	S	2023
57943	Lonesome Creek Station	3	ND	S	2015
60387	Invenergy Nelson Expansion LLC	2	IL	S	2023
1	Astoria Station	1	SD	S	2021
61242	Tres Port Power, LLC	1	TX	S	2019
61966	Victoria Port Power II LLC	2	TX	S	2022
62548	SJRR Power LLC	2	TX	S	2022
63259	Delta Energy Park	1	MI	S	2022
63335	HO Clarke Generating	3	TX	S	2021
63688	Topaz Generating	10	TX	S	2021
64383	Braes Bayou Plant	8	TX	S	2022
65372	Mark One Power Station	6	TX	S	2022
65373	Brotman Power Station	6	TX	S	2023