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Analyses and Tabulation of Heat Rates, Unit Commitment Generator Constraint Parameter Values and Emissions Estimates of the Electricity Generators of Power Plants in Texas

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Analyses and Tabulation of Heat Rates, Unit Commitment Generator Constraint Parameter Values and Emissions Estimates of the Electricity Generators of Power Plants in Texas

by

Paras Vaid

Thesis

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Abstract

Analyses and Tabulation of Heat Rates, Unit Commitment Generator Constraint Parameter Values and Emissions Estimates of the Electricity Generators of Power Plants in Texas

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This work analyzes and tabulates heat rates, unit commitment generator constraint parameters, and emission estimates for electricity generators within the Electric Reliability Council of Texas (ERCOT) grid. The heat rate is the amount of fuel required to generate one unit of electricity. It is a measure of the efficiency of a generator. The thesis describes the method(s) for determining heat rate values, using the heat input to the generator and the net generation of power and, in some cases, heat. The heat rate results developed in this work are compared to earlier datasets. This work also develops and quality assures emission rate estimates for oxides of nitrogen (NOx), sulfur dioxide (SO_2) and carbon dioxide (CO_2) that have been derived from sources such as the Emissions and Generation Resource Integrated Database (eGRID).

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Chapter 1: Introduction

The past decade has seen rapid expansion in the production of natural gas (NG) in the United States using horizontal drilling and hydraulic fracturing[1]. The Energy Information Administration (EIA) projects that NG production in the U.S. will continue to increase at least through 2040[2]. The U.S. became a net NG exporter on an annual basis in 2017 and is projected to become a net energy exporter by 2020[3]. This level of NG production has driven an increase in electrical energy generation from natural gas, with the development of new NG-fired power plants and the closing of some coal plants[3]. In addition to lower NG prices contributing to widespread use of NG for electricity generation, NG has lower carbon dioxide emissions, per unit of energy produced when combusted, compared to coal[4].

Analysis of power plant emissions and cost optimization studies require various types of data related to electricity generators, including their heat rates, fixed and variable costs associated with electricity generation, pollutant emissions, and other parameters. In the United States, multiple government agencies collect these data[5]. One source is the Emissions and Generation Resource Integrated Database (eGRID), maintained by the U.S. Environmental Protection Agency (EPA). However, no single data set assembles all parameters of interest and data are frequently updated. The goal of this thesis will be to assemble data on the Electric Reliability Council of Texas (ERCOT) in a quality assured data set. This work will build on earlier data sets assembled by Dr. Mort D. Webster of the Department of Energy and Mineral Engineering at Pennsylvania State University and his graduate student Zachary Stines (2016)[6]. The generator parameters documented in this work are shown in table 1:

Table 1: List of generator parameters documented in the thesis.

Plant Code	Generator Annual Net Generation (MWh)	Unit Unadjusted Annual NO_x Emissions (Tons)
Plant Name	UT Heat Rate (MMBtu/MWh)	Unit Unadjusted Ozone Season NO_x Emissions (Tons)
Generator ID	Mort Heat Rate (MMBtu/MWh)	Unit Unadjusted Annual SO_2 Emissions (Tons)
Number Of Associated Boilers	UT Heat Rate Calculation Notes	Unit Unadjusted Annual CO_2 Emissions (Tons)
Unit ID/Boiler ID	Variable O&M ($/MWh)	Source Of Emissions
Energy Source and Technology	Fixed Startup Cost ($/MW Of Capacity)	Notes
Prime Mover	Fuel Cost ($/MMBtu)	Unit Adjusted Annual NO_x Emissions (Tons)
Generator Nameplate Capacity (MW)	Ramp Time (Hours)	Unit Adjusted Ozone Season NO_x Emissions (Tons)
Minimum Load (MW)	Minimum Up Time (Hours)	Unit Adjusted Annual SO_2 Emissions (Tons)
Status	Ramp rate (MW/Hour)	Unit Adjusted Annual CO_2 Emissions (Tons)
Associated with Combined Heat & Power System (Yes/No)	Turn On Fuel Cost (MMBtu/MW of Capacity)	Unit Annual NO_x Total Output Emission Rate (Lb/MWh)
Unit Unadjusted Annual Heat Input (MMBtu)	Latest Fuel Cost as on July 2019 ($/MMBtu)	Unit Ozone Season NO_x Total Output Emission Rate (Lb/MWh)
Electric Allocation Factor	References	Unit Annual SO_2 Total Output Emission Rate (Lb/MWh)
Unit Adjusted Annual Heat Input (MMBtu)	Unit Ozone Season Net Generation (MWh)	Unit Annual CO_2 Total Output Emission Rate (Lb/MWh)

This study focuses on Texas, and specifically power plants within the ERCOT grid. In 2017, Texas is the top producer of oil and gas in the U.S.[7] ERCOT is the Independent System Operator (ISO) that manages power delivery for more than 25 million Texas customers, representing about 90 percent of the state's electric load.[8] ERCOT has minimal interconnections with neighboring systems, such that it can be treated as an isolated power system. Texas leads the nation in wind-power generation[9]. The state has witnessed rapid increases in new NG-based and renewable-based power plants and shutdowns of coal plants in recent years[10]. Substantial growth in the transmission network has also occurred, most notably involving the rapidly growing western ERCOT regions. All these changes indicate a need for current data. The generator parameters developed in this work can be used as an input dataset to support electric power system simulation.

Chapter 2: Heat Rates of Generators

Various prime mover technologies are used for power generation in the United States. Conventional power generation is the general term applied to the production of electrical energy from coal, oil, natural gas or nuclear fuels, using the intermediary of steam. High-pressure steam is produced using these fuels. The high-pressure steam is used to turn the blades of a turbine to generate electricity, and low-pressure steam is expelled as exhaust. Simple cycle generators are gas turbine generators whereby hot compressed gas, typically generated by combusting fuels, is used to turn the blades of turbine to generate electricity. Combined cycle generators use both simple cycle and conventional power generation together to deliver higher fuel efficiency to generate electricity. Other important prime mover technologies include internal combustion (IC) engines, wind turbines, and hydraulic turbines. More detailed discussion of these systems and determination of their heat rates is provided below.

The dataset compiled in this thesis (UT 2018) is updated to the year 2018. The thesis sources the data from eGRID, U.S. Energy Information Administration's Form EIA-860 and Form EIA-923 datasets for performing various calculations associated with heat rates of generators. The versions primarily used in the thesis for these datasets are eGRID for the year 2016 referred to as *eGRID 2016*[11], Form EIA-860 for the year 2017 referred to as *2017 Form EIA- 860*[12] and Form EIA-923 for the year 2016 referred to as *2016 Form EIA-923*[13]. The eGRID 2016 dataset provides various generator parameters, most important for heat rate calculations being the heat input and annual net generation data from the generators. The eGRID 2016 dataset sources its data from the 2016 Form EIA-923 of the U.S. EIA which lists monthly heat input and net generation values for the year 2016. The 2017 Form EIA-860 provides the latest updated list of generators along with their operational status i.e. whether the generator is operating, standby, retired or newly inducted. Additionally, heat rates calculated in the thesis are compared with a reference dataset referred to Webster 2018. The Webster 2018 dataset was shared by Dr. Mort D. Webster with the Center for Energy and Environmental Resources at the University of Texas in 2018. He had prepared the dataset with 2016 data. This dataset serves as a point of comparison to heat rates values and other parameters developed in this thesis.

2.1 STEAM TURBINE GENERATORS

In a steam turbine driven generator, water is heated separately in a boiler to convert it into high-pressure steam. A plant may have one or many boilers using fuels such as natural gas, coal or nuclear isotopes to heat water. The steam is used to rotate the blades of the turbine which drives a generator to generate electricity. Low-pressure steam is exhausted. The heat rate for a steam turbine generator can be calculated by dividing the boiler annual heat input by the annual net electricity generation. It is possible to obtain generator level estimates for most plants using data available in the eGRID datasets.

2.1.1 Natural gas-fired plants

In the case of natural gas-based steam turbine generators, it is possible to find the heat rate for most of the generators separately. So, the heat rate calculations involve working at the individual generator level to find out the heat rate by dividing the heat input into the boiler associated with a generator by the annual net generation of power from that generator. However, for some plants, an average heat rate approach is adopted in order to create a quality assured dataset for this thesis. For example, for the ‘Ray Olinger’ plant (code: 3576), the heat rates for the individual generators with generator IDs 1, 2 and 3 are calculated to be: 35.023, 13.651, 12.158 MMBtu/MWh respectively (refer to Appendix A attached as a supplementary file). The eGRID data reports five significant figures for heat rate in the units of Btu/kWh. The heat rate value of 35.023 MMBtu/MWh for one of the generators is above the usual range for natural gas-based steam turbine generators. This usual range is between 5 and 15 MMBtu/MWh with most of the heat rate values lying between 10 to 13 MMBtu/MWh. This range is based on heat rate records from the eGRID 2016[11], eGRID 2014[14], eGRID 2012[15] datasets, the Webster 2018 dataset and the heat rate calculations performed in this thesis, attached as appendix A. Therefore, in the case of 'Ray Olinger' plant, an average heat rate is calculated by dividing the 'total annual adjusted heat input' by the 'total annual net generation' (defined in glossary) by the generators as shown below. For generators with generators IDs 1, 2 and 3 and associated boiler IDs CE1, BW2, BW3 respectively,

Average heat rate = Annual heat input for (CE1+ BW2 + BW3) / Annual net generation by (1+ 2 + 3).

= (1506 + 74956 + 261288) MMBtu / (43 + 5491 + 21498) MWh

= 12.498 MMBtu/MWh.

Note: The values of annual heat input and annual net generation for each generator taken in above calculation and in subsequent calculations for other generators have been documented in Appendix A.

For another power plant called 'Powerlane' (plant code: 4195), the eGRID database doesn't report the annual heat input data for one of the boilers (boiler ID 1) in its 2016 as well as 2014 datasets.

Therefore, average heat rate = Annual heat input for (1+ 2 + 3) / Annual net generation by (ST1+ ST2 + ST3).

= (No data + 133199 + 119348) MMBtu / (2213 + 7221 + 7499) MWh

= 14.914 MMBtu/MWh.

For the ‘Point Comfort Operations’ plant (code: 52069), an average heat rate is also calculated. This is because it has four generators with six associated boilers but it is not possible to know how much of the steam energy input is being delivered by a specific boiler to a specific generator to generate electricity. Although, the boiler generator associations are described in the 2017 Form EIA-860[12] Data - Schedule 6A, 'Boiler / Generator Associations' spreadsheet, the form shows that each of the generators is associated with all six boilers. This is the only case among the natural gas-based steam turbine generators in ERCOT with this feature; all others have one boiler associated with one generator. So, an average value of generator heat rate is adopted by summing the total heat input into these six boilers and dividing that by the total annual net generation of the four generators as follows. For generators with generator IDs GEN1, GEN2, GEN3 and GEN4 and associated boilers with boiler IDs HP1, HP2, HP3, HP4, HP5 and HP6:

Average heat rate = Annual heat input for (HP1 + HP2 + HP3 + HP4 + HP5 + HP6) / Annual net generation by (GEN1 + GEN2 + GEN3 + GEN4).

= (188736 + 8887 + 81150 + 106166 + 106401 + 18241) MMBtu / (36591 + 8686 + 42201 + 3500) MWh

= 5.601 MMBtu/MWh

A comparison between the heat rates calculated in this work and those in the Webster 2018 dataset is shown in figure 1.

Figure 1: Comparison of heat rates between Webster 2018 and UT 2018 datasets for natural gas-based steam turbine generators of electric power plants.

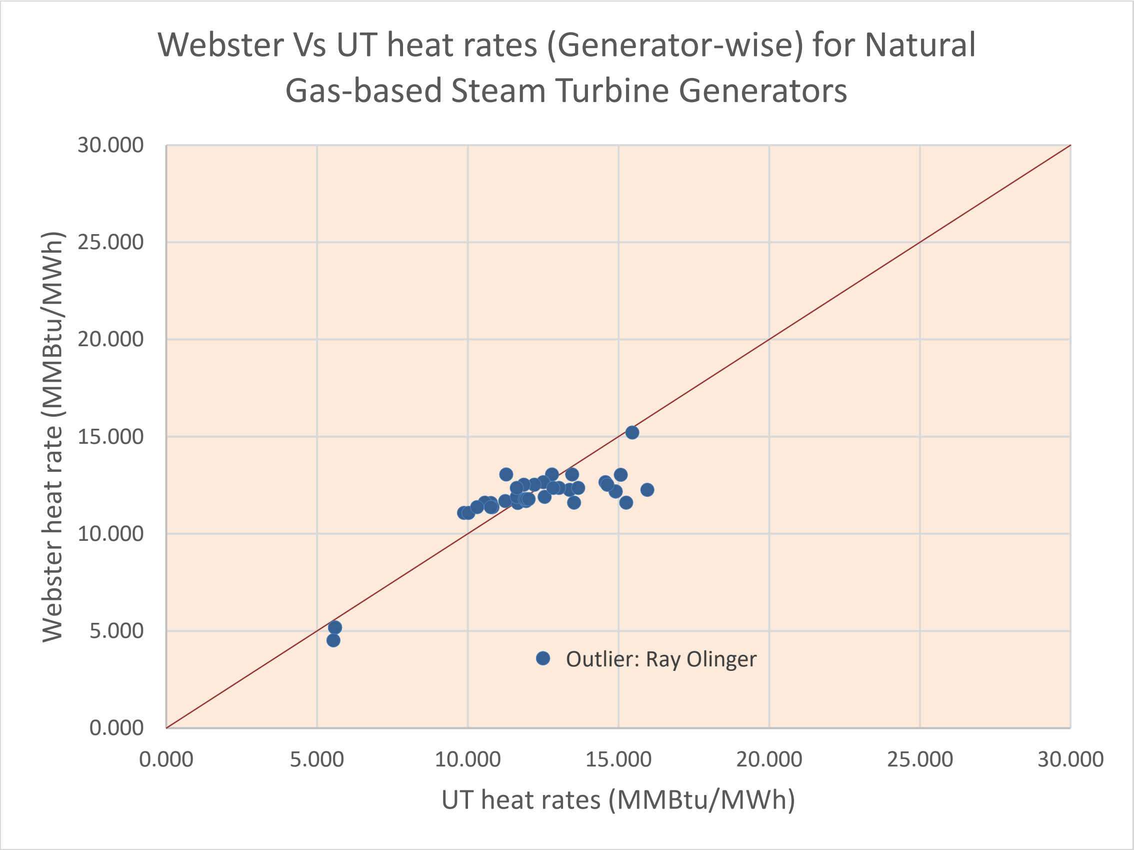


Table 2: Heat rate data of natural gas-based steam turbine generators of 'Ray Olinger' plant (code: 3576) for years 2016, 2014 and 2012.

Year and Reference	Total Annual Heat input (MMBtu)	Total Annual Net generation (MWh)	Average Heat rate (MMBtu/MWh)
eGRID 2016 UNIT and GEN spreadsheet[11]	337850	27032	12.498
eGRID 2014 UNIT and GEN spreadsheet[14]	371754	27552	13.492
eGRID 2012 UNIT and GEN spreadsheet[15]	No data	No data	No data

The outlier in figure 1 is the ‘Ray Olinger’ plant for which the heat rate determined in this work is 12.498 MMBtu/MWh based on the eGRID 2016 dataset while Webster’s heat rate is 3.598 MMBtu/MWh. Here, it is important to note that a heat rate below 3.413 MMBtu/MWh is infeasible. Since 1 MWh is equivalent to 3.413 MMBtu, a minimum of 3.413 MMBtu heat input is required to generate 1 MWh electricity, even if a plant is 100% efficient. The laws of thermodynamics further limit the conversion of heat into work (electricity), and at normal operating temperatures of power plants, an efficiency of ~70% is the maximum allowed by the laws of thermodynamics for conversion of heat into electricity in a steam power plant. Therefore, the heat rate developed in this thesis is used for this power plant.

For the ‘Powerlane’ plant, the average heat rate value adopted is obtained from the eGRID2014 dataset. This value of 14.914 MMBtu/MWh for the year 2014 seems more reasonable than the comparatively recent 2016 value of 24.935 MMBtu/MWh, as already discussed and shown in table 3 for comparison.

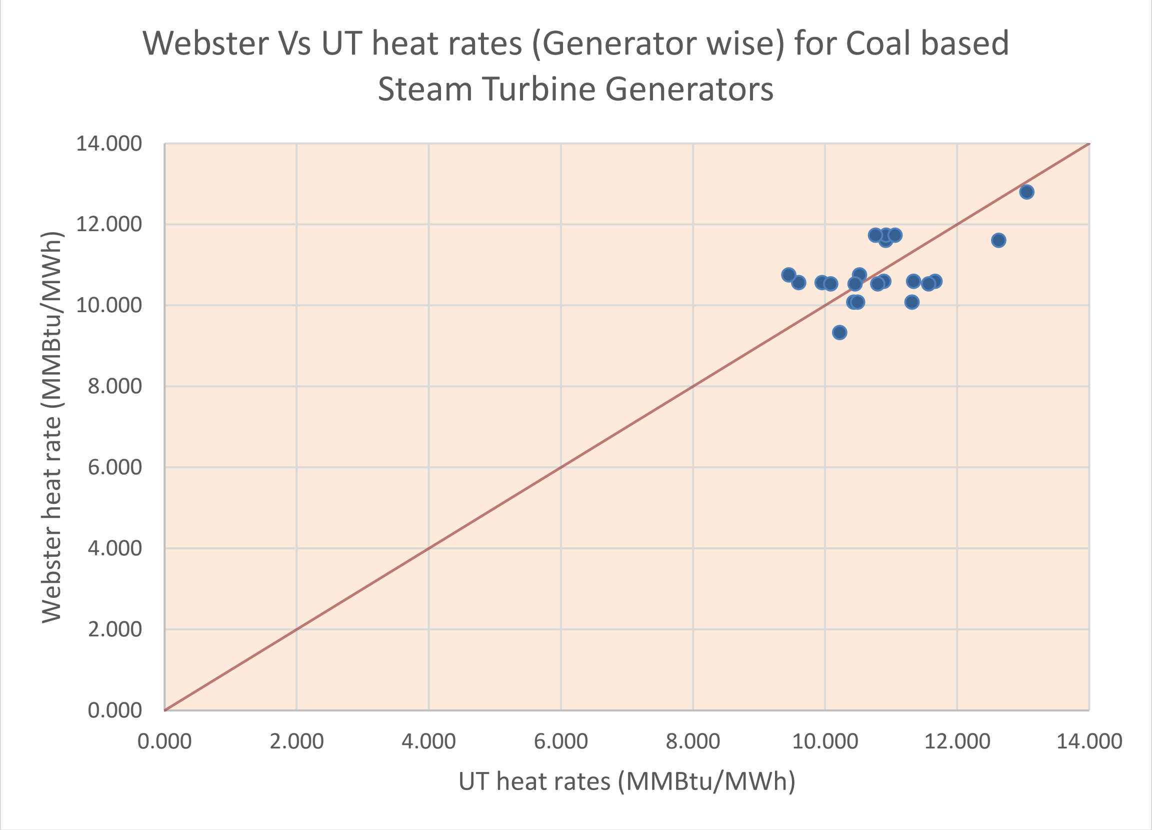
Table 3: Heat rate data of natural gas-based gas turbine generators of ‘Powerlane’ plant (code: 4195) for years 2016, 2014 and 2012.

Year and Reference	Total Annual Heat input (MMBtu)	Total Annual Net generation (MWh)	Average Heat rate (MMBtu/MWh)
eGRID 2016 UNIT and GEN spreadsheet[11]	218882	8778	24.935
eGRID 2014 UNIT and GEN spreadsheet[14]	252547	16933	14.914
eGRID 2012 UNIT and GEN spreadsheet[15]	No data	No data	No data

2.1.2 Coal-fired plants

The heat rate for each for coal-based steam turbine generators have been calculated by dividing the heat input into the boilers associated with the generators by the annual net electricity generation from the generators. Unlike natural gas-based steam turbine generators, there are no exceptions to this calculation approach. The same methodology is used to find the heat rate for each coal-based steam turbine generator. Comparisons of heat rates for coal-based steam turbine generators developed in this work with those from the Webster 2018 data indicate generally good agreement, as shown in figure 2 below:

Figure 2***:*** Comparison of heat rates between Webster 2018 and UT 2018 datasets for coal based-steam turbine generators of electric power plants.



2.2 GAS-BASED TURBINE GENERATORS

For gas turbine generators, the fuel, typically natural gas or other gases, is mixed with compressed air. The mixture is then burned to a very high temperature and the resulting combustion gases are used to spin the blades of turbine which then converts a portion of spinning energy into electricity.

Most power plants in Texas use NG as fuel to run the gas turbine generators. The net annual electricity generation from such generators is listed in the eGRID 2016 dataset. The eGRID dataset sources its database from the Form EIA-923[13] from the U.S. Energy Information Administration (EIA) which lists monthly heat input and net generation values for the year 2016. The values given in Form EIA-923 are listed for each generator separately in a spreadsheet called 'Page 4 Generator Data' only for the combined cycle and steam turbine generators but not for the gas turbine generators. In Form EIA-923, in a separate spreadsheet called 'Page 1 Generation and Fuel Data', the values are listed for different prime mover technologies and fuel types but not for each generator separately.

The 'Page 1 Generation and Fuel Data' spreadsheet of eGRID gives the net generation values at the plant level for natural gas-based gas turbine generators. eGRID divides the annual net generation among the gas turbine generators in proportion to the generator nameplate capacity as described in the Technical Support Document, eGRID 2016.[16]

As an example, data from eGRID 2016 for the 'T.H. Wharton' plant (code: 3469) are summarized in table 4:

Table 4: Table showing the distribution of annual net generation in the proportion of nameplate capacity for ‘T.H. Wharton’ plant (code: 3469) using data from eGRID 2016.

Generator ID	Generator Nameplate Capacity (MW)	Generator annual net generation (MWh)
51	85.0	3400
52	85.0	3400
53	85.0	3400
54	85.0	3400
55	85.0	3400
56	85.0	3400
GT1	16.3	652

It is not possible to arrive at the exact value of annual net electricity generation for each gas turbine generator. Therefore, an average heat rate for the gas turbine generators at the ‘T.H. Wharton’ plant is calculated. For generator IDs 51, 52, 53, 54, 55, 56 and GT1:

Average heat rate = Annual heat input for (51 + 52 + 53 + 54 + 55 + 56 + GT1) / Annual net generation by (51 + 52 + 53 + 54 + 55 + 56 + GT1).

= (86836 + 57687 + 167943 + 42863 + 79510 + 118342 + No data) MMBtu / (3400 + 3400 + 3400 + 3400 + 3400 + 3400 + 652) MWh

= 26.281 MMBtu/MWh.

The same calculation approach is adopted for all the natural gas-based gas turbine generators. The Webster 2018 dataset also used an average heat rate approach for all the natural gas-based gas turbine generators as discussed above. The scatterplot comparison between the two datasets in figure 3, shows two outliers which correspond to the ‘T.H. Wharton’ plant (code: 3469)’ and ‘Greens Bayou’ plant (code: 3464)’.

Figure 3***:*** Comparison of heat rates between Webster 2018 and UT 2018 datasets for natural gas-based gas turbine generators in power plants.

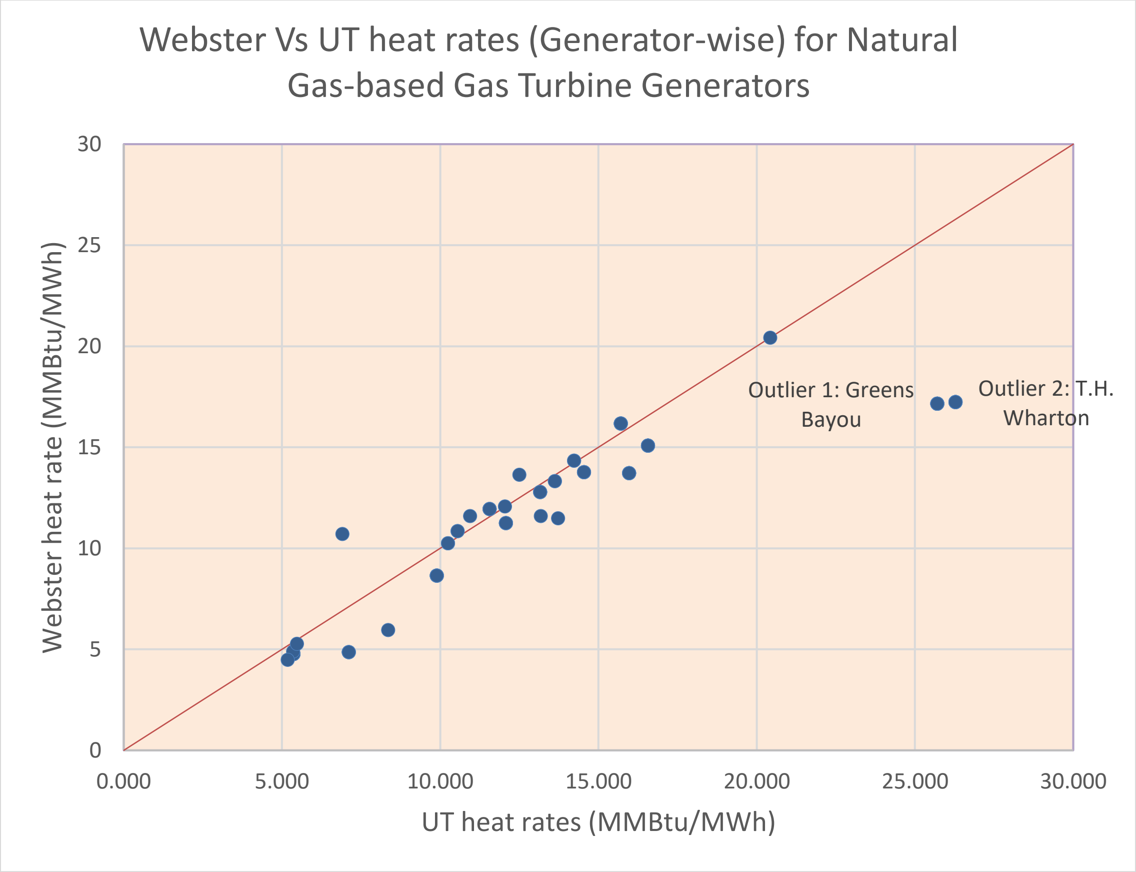


Table 5: Heat rate data of natural gas-based gas turbine generators of 'Greens Bayou' plant (code: 3464) for years 2016, 2014 and 2012.

Year and Reference	Total Annual Heat input (MMBtu)	Total Annual Net generation (MWh)	Average Heat rate (MMBtu/MWh)
eGRID 2016 UNIT and GEN spreadsheet**[11]**	390223	23118	25.701
eGRID 2014 UNIT and GEN spreadsheet**[14]**	202442	10498	19.284
eGRID 2012 UNIT and GEN spreadsheet**[15]**	62005	No data	No data

Figure 3 shows outlier 1 i.e. 'Greens Bayou' plant. For this plant, as seen from table 5, the average heat rate in this work (25.701 MMBtu/MWh) is based on the eGRID 2016 dataset**[11]**, whereas the source of Webster's average heat rate (17.149 MMBtu/MWh) cannot be traced. The heat rate value of 25.701 MMBtu/MWh is on the high end of the usual range of heat rate for natural gas-based gas turbine generators which is between 5 to 27 MMBtu/MWh. This range is based on heat rate records from eGRID 2016**[11]**, eGRID 2014**[14]**, eGRID 2012**[15]** datasets, the Webster 2018 dataset and the heat rate calculations in this work, shown in Appendix A. With no further information to discriminate between the heat rate values, the heat rate calculated in the work will be used.

Table 6: Heat rate data of natural gas-based gas turbine generators of ‘T.H. Wharton’ plant (code: 3469) for years 2016, 2014 and 2012.

Year and Reference	Total Annual Heat input (MMBtu)	Total Annual Net generation (MWh)	Average Heat rate (MMBtu/MWh)
eGRID 2016 UNIT and GEN spreadsheet[11]	553181	21049	26.281
eGRID 2014 UNIT and GEN spreadsheet[14]	311542	12001	25.960
eGRID 2012 UNIT and GEN spreadsheet[15]	833879	No data	No data

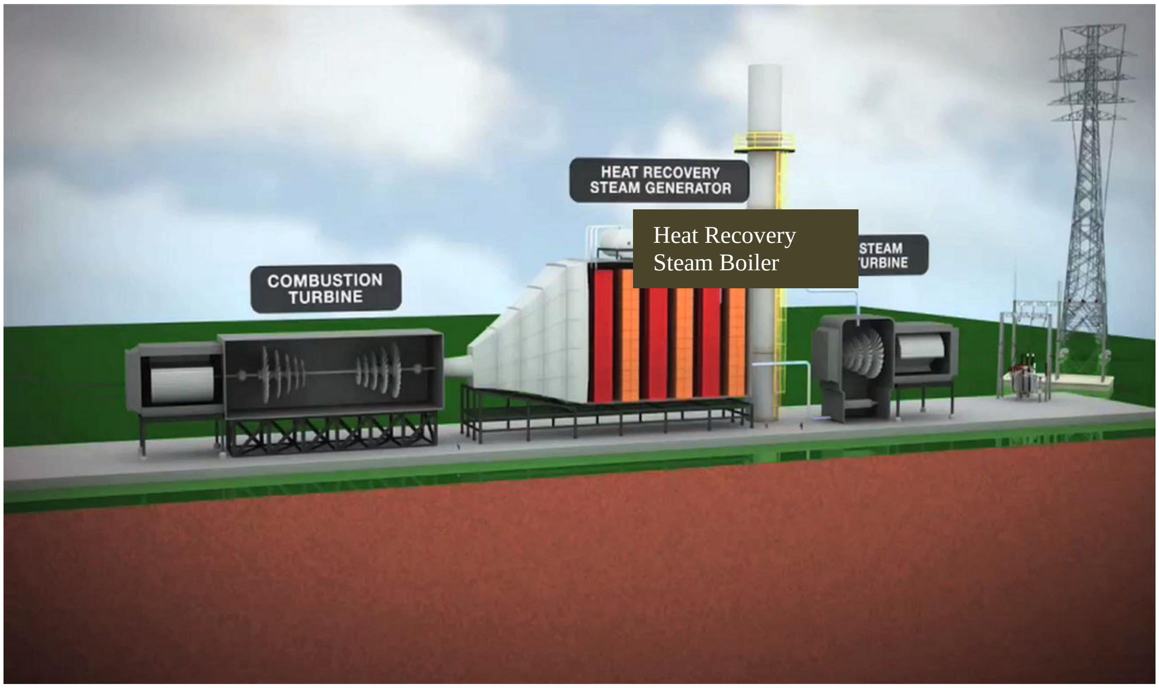
As for the ‘Greens Bayou’ plant, with no further information to discriminate between the heat rate values, the heat rate calculated in the work will be used.

2.3 NATURAL GAS COMBINED CYCLE GENERATORS

A combined cycle power plant uses both gas and steam turbines to produce up to 50 percent more electricity from the same fuel input than a traditional simple cycle plant[17]. A combined cycle generator system involves interlinkage of a combined cycle combustion turbine generator and a steam turbine generator. The waste heat from the combustion turbine is utilized by the boiler to generate additional electricity. In this way, the combined cycle generator technology is different from the other conventional technologies such as a steam turbine, gas turbine or internal combustion as in those technologies, each generator acts as an independent unit for the purpose of flow of heat energy.

The operation of a combined cycle power plant can be understood by examining the functions of its various components, shown schematically in figure 4[18]. The fuel, typically natural gas, is mixed with compressed air. The mixture is then burned to a very high temperature and the resulting combustion gases are used to spin the blades of a turbine that converts a portion of the spinning energy into electricity. The heat recovery steam boiler captures waste heat (hot exhaust which would otherwise escape) from the combustion turbine and feeds it into boilers to produce steam. The steam, produced in the heat recovery steam boiler, is used to spin the blades of steam turbine which then drives the generator to generate additional electricity.

Figure 4***:*** Schematic diagram representing major components of a typical combined cycle power plant.



2.3.1 Heat Rate Calculations

In order to determine the exact flow of heat energy in combined cycle plants, a detailed study of generator boiler relationships has been performed for each plant separately and heat rates calculated using two different methods as discussed below.

2.3.1.1 Average heat rate

This method is illustrated by calculations for the 'Lamar Power Project' plant (code: 55097). It has six combined cycle generators of which four (CTG 1-4) are combustion turbine generators and the remaining two (STG 1-2) are steam turbine generators. In this approach, the average heat rate for all six combined cycle generators is calculated by dividing the 'total annual adjusted heat input' by the 'total annual net generation'. These values are shown in table 7 below. The average value thus found, is assigned to all the six combined cycle generators of the 'Lamar Power Project' plant.

Table 7: Details of the combined cycle generators of 'Lamar Power Project' plant (code: 55097).

Serial Number	Generator ID	Number of associated boilers	Unit ID/Boiler ID	Unit adjusted annual heat input (MMBtu)	Generator annual net generation (MWh)
1	CTG1	0	1	10654294	987826
2	CTG2	0	2	10358063	901478
3	CTG3	0	3	10169814	894750
4	CTG4	0	4	11026016	1026451
5	STG1	2	Boiler HRSG 1, 2	No data	1112897
6	STG2	2	Boiler HRSG 3, 4	No data	1130481

Average heat rate for all combined cycle generators from Sr. No. 1 to 6 =

= (Total annual heat input for CTG1, CTG2, CTG3, CTG4**) / (**Total annual net generation for CTG1, CTG2, CTG3, CTG4, STG1, STG2**)**

= (10654294 + 10358063 + 10169814 + 11026016**)** MMBtu **/ (** 987826 + 901478 + 1112897 + 894750 + 1026451 + 1130481**)** MWh

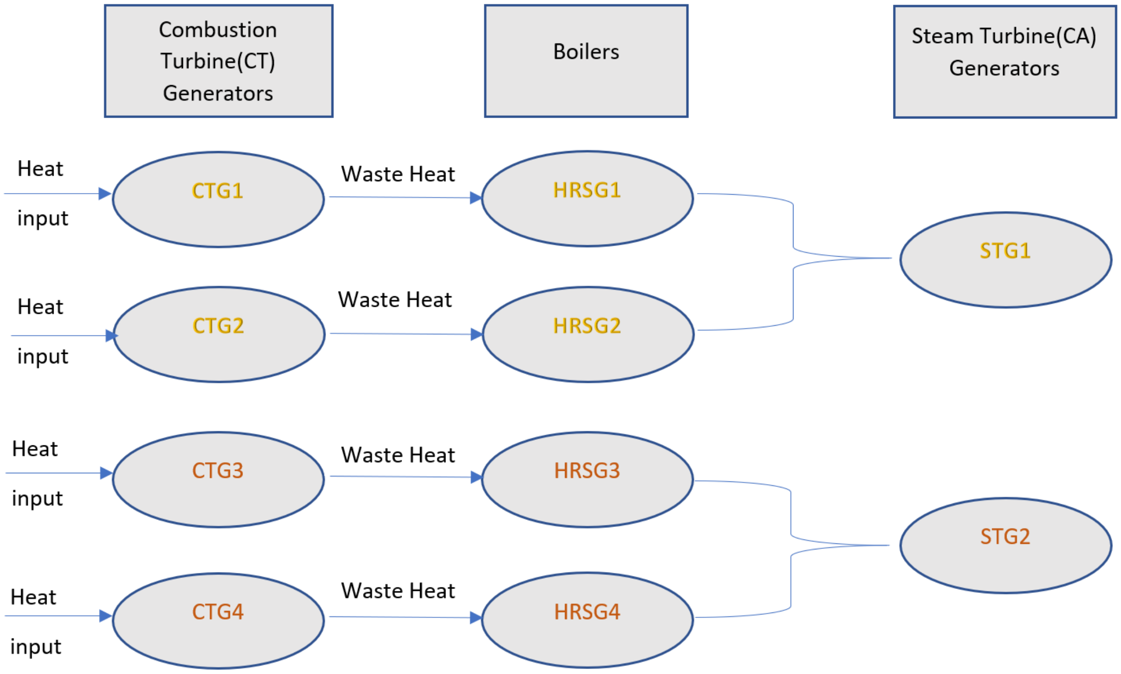
= **<u>6.972</u>** **<u>MMBtu / MWh.</u>**

2.3.1.2 Exact calculation using boiler generator relationships

This method accounts for the interconnections between various generators and boilers and the exact flow of heat energy among them. Such relationships are traced from the *2017 Form EIA-860 Data - Schedule 6A, 'Boiler / Generator Associations' Spreadsheet.*[12] Waste heat from the combustion turbines (CT) goes to boilers to heat up the water to produce steam, which in turn is used to run steam turbines (CA) to generate additional electricity. So, the CT generator is mapped to its corresponding boiler which in turn is mapped to the corresponding CA generator to identify the exact flow of energy.

This approach is again illustrated by the ‘Lamar Power Project’ plant, however, in this case, the flow between turbines, boilers and generators is assumed to be known, as shown in figure 5. Waste heat from the combustion turbines associated with generators CTG1 and CTG2 goes to boilers HRSG1 and HRSG2 respectively. These boilers use the waste heat to produce steam which in turn runs the steam turbine associated with generator STG1. Similarly, waste heat from the combustion turbines associated with generators CTG3 and CTG4 goes to boilers HRSG3 and HRSG4 respectively, which in turn produce steam to run the steam turbine associated with generator STG2.

Figure 5: Flow of heat energy among combined cycle generators and boilers in ‘Lamar Power Project’ plant.



The heat rate calculations can be described as:

Average Heat rate for generators CTG1, CTG2, STG1 =

= **(**Total annual heat input for CTG1, CTG2**)** **/** **(**Total annual net generation for CTG1, CTG2, STG1**)**

= (10654294 + 10358063) MMBtu / (987826 + 901478 + 1112897) MWh

= **6.999 MMBtu / MWh**

Average Heat rate for generators CTG3, CTG4, STG2 =

(Total annual heat input for CTG3, CTG4**)** **/** **(**Total annual net generation for CTG3, CTG4, STG2**)**

= (10169814 + 11026016) MMBtu / (894750 + 1026451 + 1130481) MWh

= **6.946 MMBtu / MWh**

2.3.2 Heat rate comparisons

The Webster 2018 dataset applied the average heat rate approach discussed above. The scatterplot of generator-wise comparison between the datasets shows one outlier, which corresponds to the generators of the ‘CCCL Signal Hill’ plant (code: 50127).

Figure 6*:* Comparison of heat rates between Webster 2018 and UT 2018 datasets for natural gas-based combined cycle generators in power plants.

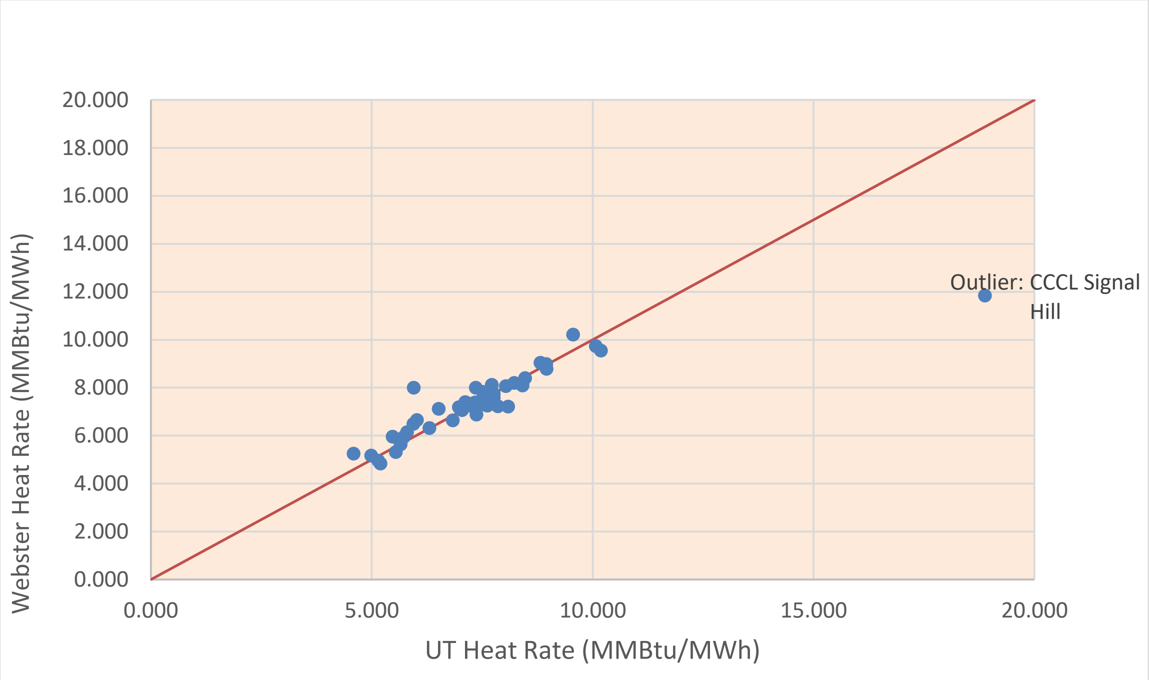


Table 8: Heat rate data of natural gas-based combined cycle generators of the 'CCCL Signal Hill LLC' plant (code: 50127) for years 2016, 2014 and 2012.

Year and Reference	Total Annual Heat input (MMBtu)	Total Annual Net generation (MWh)	Average Heat rate (MMBtu/MWh)
eGRID 2016 UNIT and GEN spreadsheet[13]	77837	4122	18.883
eGRID 2014 UNIT and GEN spreadsheet[14]	43630	3687	11.833
eGRID 2012 UNIT and GEN spreadsheet[15]	No data	6700	No data

As seen from table 8, the average heat rate determined in this work (total annual heat input/ total annual net generation = 77,837/4,122 = 18.833 MMBtu/MWh) is based on the eGRID 2016 dataset[11], whereas Webster's average heat rate (=11.83 MMBtu/MWh) is based on the eGRID 2014 dataset[14]. The heat rate value of 18.833 MMBtu/MWh is on the high end of the expected range, which is between 4.5 to 19 MMBtu/MWh from the eGRID 2016[11], eGRID 2014[14], eGRID 2012[15], Webster 2018 dataset and the heat rate calculations performed in this work (refer to Appendix A). With no further information to discriminate between the heat rate values, the heat rate calculated in the work will be used.

2.4 OTHER PRIME MOVER TECHNOLOGIES AND FUELS

Heat rates are not calculated for renewable sources of electricity generation such as wind or hydraulic turbines. For the combined cycle single shaft prime mover technology, the heat rate is calculated for each generator individually. For the IC prime mover technology, the heat input and annual net generation are reported at the plant level. Thus, for this type of prime mover, an average plant level heat rate is calculated and assigned to all IC prime mover type generators of that plant. No outliers are identified when compared to the Webster 2018 dataset.

2.5 COMBINED HEAT AND POWER PLANTS

The adjustment methodology for combined heat and power (CHP) plants is designed to allocate heat input for CHP plants between electricity and thermal output as described in the Technical Support Document of eGRID 2016 [16]. If a plant is a CHP plant, the adjustment is applied to the heat input for the entire plant.

The methodology is based on multiplying heat input by an electric allocation factor, which is calculated as follows:

1. Calculate the useful thermal output. EIA-923[13] reports both total fuel consumption and fuel consumption for electricity generation. The useful thermal output value for eGRID2016 data is calculated from EIA-923 data as 0.8 multiplied by the difference in total heat input and electricity heat input in MMBtu. The value of 0.8 is an assumed efficiency factor from the combustion of the consumed fuel.
   Useful Thermal Output = 0.8 X (Total Heat Input – Electric Heat Input)
2. The electric allocation factor is calculated as the ratio of the electricity output to the sum of the electricity and steam heat outputs, where the electricity heat output is the net generation in MWh multiplied by 3.413 to convert it to MMBtu, and steam heat output is 0.75 multiplied by the useful thermal output, in MMBtu. The 0.75 factor is another assumed efficiency factor, which accounts for the fact that once fuel is combusted for electricity generation, approximately 75% of the useful thermal output can be utilized for other purposes, such as space heating or industrial processes.

Electric Allocation Factor = (3.413 X Net Generation) / [(0.75 X Useful Thermal Output) + (3.413 X Net Generation)]

If the useful thermal output is zero, then the electricity allocation factor is set to one. The electric allocation factor should be between zero and one. If the electric allocation factor is calculated to be greater than one, it is set to one, and if the electric allocation factor is calculated to be less than zero, it is set to zero.

Thus, this chapter explores and describes the heat rate calculation methods for different prime mover technologies and suggests a suitable method for each scenario. However, there are instances when some generators offer a new situation requiring a different calculation as discussed in Appendix-B: Additional Special Cases.

Chapter 3: Unit Commitment Generator Constraint Parameters

Unit commitment generator constraint parameters include the cost parameters related to the various operations associated with running the generators. These cost related parameters along with other generator parameters can be used as an input dataset to any updated generator level model to support electric power system simulation. These cost related parameters find application in generator level cost optimization studies and cost comparison analysis among different scenarios. Stines (2016)[6] established a set of unit commitment generator constraint parameter values for the electrical generating units of Texas, as tabulated below. In addition to these parameters, there's another set of such parameters that Dr. Webster shared with our group through personal communication in 2018. This section compares the costing parameters of Stines (2016) with those shared by Dr. Webster in 2018 in order to identify differences between the two and the reasons for observed difference(s).

3.1 STINES 2016 PARAMETER VALUES

The following table shows the unit commitment generator constraint parameter values from Stines (2016)[6]. Variable operating and maintenance (O&M) costs are from Craig et al. (2016)[19].

Table 9: Unit commitment generator constraint parameter values by Stines (2016).

Fuel Type	Prime mover	Capacity (MW)	Variable O & M cost ($/ MWh)	Fixed Start-up cost ($/ MW)	Fuel Cost ($/ MMBtu)	Minimum Up Time (hrs)	Ramp rate (% Cap / Hrs)	Turn on fuel use/ Start up fuel use (MMBtu/ MW)
Coal	ST	< 300	3	33	2.38	16	60	16.7
Coal	ST	> 300	3	33	2.38	16	60	16.7
Petroleum coke, purchased steam	ST	any	<=100 MW 5, 100-200 MW 4, >200 MW 3.	33	3.42	16	30	16.7
Other Gases	GT	any	7	12.5	3.42	1	100	0
Waste Heat	ST	any	4	33	0	16	100	16.7
Wood Waste Solid	ST	any	4	33	0	16	100	16.7
Nuclear	ST	any	4	74	0	24	10	7.4
Natural Gas	ST	any	<=100 MW 5, 100-200 MW 4, >200 MW 3.	33	3.42	16	100	16.7
Natural Gas	CA, CS,CT	any	2.5	12.5	3.42	12	100	2.5
Natural Gas	GT	< 100	7	12.5	3.42	1	100	0
Natural Gas	GT	> 100	7	12.5	3.42	1	100	0
Natural Gas	IC	< 100	3	12.5	3.42	1	100	0
Natural Gas	IC	> 100	3	12.5	3.42	1	100	0
Renewables (Solar, Wind) and DC	Any	any	No data	No data	0	1	100	No data

3.2 WEBSTER 2018 PARAMETER VALUES

The following table 10 shows the unit commitment generator constraint parameter values from the Webster 2018 dataset.

Table 10: Unit commitment generator constraint parameter values by Webster 2018.

Fuel Type	Prime mover	Capacity (MW)	Variable O & M cost ($/ MWh)	Fixed Start-up cost ($/ MW)	Fuel Cost ($/ MMBtu)	Minimum Up Time (hrs)	Ramp rate (% Cap / Hrs)	Turn on fuel use/ Start up fuel use (MMBtu/ MW)
Coal	ST	< 300	3	160	2.3	24	60	9
Coal	ST	> 300	3	115	2.3	24	60	14
Petroleum coke, purchased steam	ST	any	3	100	5	6	120	5
Other Gases	GT	any	3	100	5	1	840	0.25
Waste Heat	ST	any	3	100	1	24	60	5
Wood Waste Solid	ST	any	4.2	100	2.29	12	60	5
Nuclear	ST	any	4	10000	0	168	6	0
Natural Gas	ST	any	4	100	3	8	60	5
Natural Gas	CA,CS,CT	any	4.5	85	3	6	840	0.25
Natural Gas	GT	< 100	5	35	3	1	840	0.25
Natural Gas	GT	> 100	5	110	3	1	840	0.25
Natural Gas	IC	< 100	6	35	3	0	840	0.1
Natural Gas	IC	> 100	6	110	3	0	840	0.1
Renewables (Solar, Wind) and DC	Any	any	0	0	0	0	6000	0

3.3 COMPARISONS BETWEEN STINES 2016 AND WEBSTER 2018 PARAMETER VALUES

Variable operations and maintenance (O&M) costs between the Stines 2016[6] and Webster 2018 data are in good agreement. However, there are significant differences between the fixed start-up costs for different fuels. In particular, for nuclear fuel, the value of fixed start-up cost for the Webster 2018 dataset is 10,000 $/MW versus 74 $/MW in Stines 2016. Such a high value may have been assigned to account for the fact that nuclear plants rarely cycle off and then start up again. As per Schill et al. (2016)[20], start-up costs depend on off time, i.e. on a generator's temperature at the time it is started up again. As modeling off time-dependent start-up costs is computationally demanding, a simplified approach can be adopted. Specifically, nuclear plants are generally assumed to carry out only hot starts, requiring only thirty percent of the cold start fuel requirement. Thus, to account for the fact that the start-up fuel requirement is very high for nuclear fuel as compared to other fuels, Webster likely chose a high fixed start-up cost value. A unit commitment model simulation would be restricted in allowing nuclear plants to cycle off and then on again. Webster's parameters include non-zero values of fuel cost for waste heat[12] (i.e. heat that is the byproduct of an existing industrial process for power generation) and wood waste solids[12] (e.g., paper pellets, railroad ties, utility poles, wood chips, bark etc.), both of which are renewable fuel sources. A possible reason may be that these should be used only after using other renewable sources of energy like wind and solar.

3.4 FUEL PRICES

The latest fuel prices documented in this work have been taken from the Short-Term Energy Outlook by U.S. EIA (2019)[21] which also projects future values. The following table represents the fuel prices for the third quarter of 2019:

Table 11: Fuel prices for third quarter of 2019 as per Short-Term Energy Outlook by U.S. EIA (2019).

Fuel Type	Fuel Price ($/ MMBtu)
Coal	2.12
Natural Gas	2.76
Residual Fuel oil	13.83
Distillate fuel oil	17.23

In addition, Craig et al. (2018)[22] provides the following fuel prices by year as shown in table 12. The comparison of table 12 cost estimates with that of table 11 show that different cost projection studies done at different points in time may give different estimates for some of the fuel types. Therefore, the table 11 estimates are adopted in the present study since they are the latest and thus seem most reliable.

Table 12: Fuel prices by year as per Craig et al. (2018).

Fuel Type	Fuel Price ($/ MMBtu)			
	2015	2025	2035	2045
Coal	2.1	2.2	2.2	2.3
Natural Gas	3.2	5.2	5.2	5.2
Oil	14.6	20.6	25.6	28.5
Uranium	0.8	0.9	1.0	1.0
Landfill gas	0.0	0.0	0.0	0.0
Non-fossil waste	0.0	0.0	0.0	0.0
Biomass	1.8	1.8	1.8	1.8

Note: The above table takes uranium prices from the Annual Energy Outlook (2015) of U.S. EIA[23]; Landfill gas and non-fossil waste prices from the Integrated Planning Model documentation (2013) of U.S. Environmental Protection Agency[24] and all other prices from the Annual Energy Outlook (2016) of U.S. EIA[22].

The dataset prepared in this work (refer to Appendix A) uses the values of variable O&M cost, fixed start-up cost, fuel cost, minimum up time, ramp rate and turn on fuel use from the Webster 2018 dataset shown in table 10. This is because for the values which are different in Stines 2016 and Webster 2018 datasets, the reasoning given above suggests the Webster 2018 values are preferred compared to those of Stines 2016. In addition, the dataset prepared in this thesis incorporates the latest fuel prices for coal and natural gas for the third quarter of 2019 from table 11.

Chapter 4: Power Plant Emissions

This work aims to document the emissions and emission rate estimates at the generator level (attached as Appendix A). However, the eGRID 2016[11] database contains such values at the plant level. The calculations for adjusted emissions and the adjusted emission rate estimates have been performed on the same principles as that adopted for the heat rate calculations to derive generator level heat rate values. So, for the natural gas-based combined cycle, gas turbine and internal combustion generators of a power plant, the *average* emissions rate estimate is adopted. On the other hand, for natural gas and coal-based steam turbine generators and natural gas-based combined cycle single shaft generators, emission rate values for each generator are calculated separately. In the case of biomass-based fuels, the calculations of emissions and emissions rate estimates require adjustments resulting in a different approach than that adopted for the heat rate calculations. Detailed discussion of these approaches is presented below.

4.1 DATA AVAILABLE IN GOVERNMENTAL INVENTORIES

Gaseous emissions from power plants include SO_2, CO_2, NO_x, nitrous oxide (N_2O), carbon dioxide equivalent (CO_{2e}) and methane (CH_4). CO_{2e} emissions are calculated based on the global warming potential (GWP) of CO_2, CH_4, and N_2O. GWP is a value assigned to a greenhouse gas so that the emissions of different gases can be assessed on an equivalent basis to the emissions of the reference gas, CO_2.[16] This work documents the emissions and emissions rate estimates by referring to the Emissions and Generation Resource Integrated Database (eGRID) 2016[11] which is prepared by the Clean Air Markets Division (CAMD) of the U.S. Environmental Protection Agency. The eGRID 2016 database has the following values:

1. At the plant level, annual input emission rate (lb/MMBtu), annual output emission rate (lb/MWh) and annual unadjusted and adjusted emissions (tons) of following gases:

   SO_2, CO_2, NO_x (annual), NO_x (ozone season i.e. May through September), N_2O, CO_{2e} and CH_4.
2. At the generator level, only unadjusted annual emissions (tons) are available for following gases:

   SO_2, CO_2, NO_x (annual) and NO_x (ozone season).

This work focuses on the emissions of SO_2, CO_2, NO_x (annual) and NO_x (ozone season i.e. May through September).

Emissions estimates from the eGRID 2016 database utilize the following sources[2]:

1. For generators that report to the CAMD of the EPA, the emission estimates are directly included from the generator level emissions data from the CAMD. Generally, emission sources that report to the CAMD are fossil fuel-fired boilers and turbines serving an electric generator with a nameplate capacity greater than 25 MW and producing electricity for sale. The CAMD uses Continuous Emissions Monitoring Systems (CEMS) to monitor the emissions of NO_x, SO_2 and CO_2.[25]
2. For generators that report to the U.S. Energy Information Administration (EIA) but not to the CAMD, the emission estimation is done by multiplying the heat input by the fuel-specific emission factors given in Appendix C[16].

4.2 APPLYING ADJUSTMENTS TO EMISSION ESTIMATES

4.2.1 Adjustments for biomass

Biomass is a fuel derived from organic matter such as wood and paper products, agricultural waste, or methane (e.g., from landfills). eGRID assumes that these materials are subject to the natural carbon cycle and, therefore, do not contribute to global warming. eGRID assigns zero CO_2 emissions to generation from the combustion of all biomass (including biogas) because these organic materials would otherwise release CO_2 (or other greenhouse gases) to the atmosphere through decomposition. In any case, either through combustion or decomposition, the carbon released into the atmosphere is sequestered back during biomass growth and thus the natural cycle continues[16].

eGRID makes adjustments for biogas emissions, for biomass emissions other than biogas, and for solid waste emissions for specified pollutants.

The emissions from biomass combustion at a plant are subtracted from the plant's overall unadjusted emissions of any gas to obtain adjusted emissions for that gas.

4.2.2 Adjustments for CHP plants

A CHP plant is a type of generating plant that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes. CHP, also known as cogeneration, can convert energy more efficiently than plants that separately produce heat and electricity.

The methodology to make adjustments for CHP plants is based on multiplying emissions and heat input by an electric allocation factor (electricity heat output / sum of electricity and steam heat output). eGRID explains the detailed procedure to calculate the electric allocation factor, described in Chapter 2.

The Technical Support Document of eGRID 2016[16] provides the formulas for finding the emission rate estimates at the plant level:

1. Input emission rate (at plant level) = Total annual *unadjusted* emissions divided by the annual heat input.
2. Output emission rate (at plant level) = Total annual *adjusted* emissions divided by annual net generation.

4.3 CALCULATION OF EMISSION RATES AT GENERATOR LEVEL

The values of adjusted emissions and the adjusted emission rate estimates have been calculated at the generator level in this work. However, these data are only available at the plant level in the eGRID 2016[11] database but not at the generator level. In order to derive the generator level emissions and emission rate estimates, the following steps were performed:

1. Extract the generator level unadjusted emissions from the unit file of eGRID 2016[11].
2. Convert the unadjusted emissions to the adjusted emissions by:
    - Multiplying by the electric allocation factor in the case of CHP plants.
    - In case of generators using biomass as fuel, determine the adjustment by multiplying the emissions factor with the heat input. Then, subtract the adjustment thus calculated from the unadjusted emissions in order to determine the adjusted emissions.
    - In the case of CHP plants that are based on biomass fuel, first apply the biomass adjustment and then the CHP adjustment.

4.3.1 Specific Cases

Examples for specific power plants are provided below to understand their calculation methodologies:

1. *Plant Name: Graham (plant code:3490)*

   The Graham power plant utilizes natural gas-fired steam turbines as the prime mover. Each generator is independent of another; thus the emissions and emission rates are calculated for each generator separately.

   For generator ID 1, the NO_x output emission rate is calculated in lb/MWh as:

   [Unit adjusted annual NOx emissions (tons) from generator ID 1/ Annual net generation (MWh) from generator ID 1] *2000

   i.e. (58.46 tons/41664 MWh) * 2000 = 2.81 lb/MWh.

   Where, the unit adjusted annual NOx emissions (tons) is obtained from the UNT16 spreadsheet of eGRID 2016 and the generator annual net generation (MWh) from GEN16 spreadsheet of eGRID 2016.[11]

   The factor of 2000 is used to convert emissions from tons to pounds.

2. *Plant Name: DeCordova Steam Electric Station (plant code:8063)*

   This plant utilizes natural gas-fired gas turbines as the prime mover. Here, the annual net generation is equal for all generators as reported in the eGRID 2016[11] dataset. Generator level data are unavailable, consequently the total plant level annual net generation is divided amongst the generators in proportion to their nameplate capacity. Therefore, it is appropriate to find an average emission rate value for the generators. This is done by dividing total NO_x emissions by the total annual net generation for all the generators; a similar procedure is used for other gases as well.

For generator ID CT1, the NO_x output emission rate in lb/MWh is calculated as: [Sum of unit adjusted annual NOx emissions (tons) from generator IDs CT1, CT2, CT3 and CT4/ Sum of annual net generation (MWh) from generator IDs CT1, CT2, CT3 and CT4] *2000

i.e. { (13.68+8.57+4.31+3.14) tons /(2510+2510+2510+2510) MWh }*2000 = 5.92 lb/MWh.

Where, the unit adjusted annual NOx emissions (tons) are obtained from the UNT16 spreadsheet of eGRID 2016 and the generator annual net generation values (MWh) from GEN16 spreadsheet of eGRID 2016.[11]

3. *Plant Name: Sam Rayburn (plant code:3631)*

   Sam Rayburn is natural gas-fired combined cycle plant. There is no emissions data available for the combined cycle steam turbine generator. Therefore, an average emission rate for the generators was determined by dividing total emissions by the total annual net generation.

   For generator ID 10, the NO_x output emission rate in lb/MWh is calculated as: [Sum of unit adjusted annual NOx emissions (tons) from generator IDs 7, 8, 9 and 10/ Sum of annual net generation (MWh) from generator IDs 7, 8, 9 and 10] *2000

   i.e. { (0.98+5.22+4.70+ No data) tons/(24667+5450+47097+39698) MWh } *2000 = 0.19 lb/MWh.

   Where, the unit adjusted annual NOx emissions (tons) are obtained from the UNT16 spreadsheet of eGRID 2016 and the generator annual net generation values (MWh) from GEN16 spreadsheet of eGRID 2016.[11]

4. *Plant Name: Central Utility Plant (plant code:10184)*

This is a natural gas-fired combined cycle plant. Emissions data are not available for the combined cycle steam turbine generator. Furthermore, since this is a combined heat and power plant, the CHP adjustment is applied by multiplying the unadjusted emissions with the electric allocation factor to determine adjusted emissions. The average emission rate is found by applying the same approach as for the 'Sam Rayburn' plant.

4.4 EMISSIONS ADJUSTMENTS FOR BIOMASS-BASED GENERATORS

1. All CO_2 emissions from any biomass fuels are adjusted to zero[16].
2. Adjustments for other pollutants i.e. NO_x, SO_2, CH_4, and N_2O are made only for landfill gas. As per the eGRID 2010 Technical Support Document[26], emissions from generation powered by renewable methane (landfill gas and digester gas) are treated as a special case in eGRID with respect to NO_x and SO_2. Landfill gas and digester gas emissions must be flared in most cases if the gas is not consumed as useful energy. eGRID determines the amount of incremental NO_x emissions attributable to utilizing renewable methane to generate electricity and assumes that renewable methane such as landfill gas or digester gas would have been flared if not used to generate electricity. This generation is then assigned the appropriate NO_x emission factor, e.g., for a boiler or internal combustion engine or turbine. These emissions are then offset by the amount of emissions represented by a typical flare:

   - For NO_x emissions, an emission factor for flaring of landfill gas, 0.000283 tons per MMBtu[27], is used.

- For SO_2 emissions from landfill gas, Table C-3 in the Technical Support Document of eGRID 2016[16] (Attached as Appendix C) gives the emission factors for different prime movers as tabulated below. The plants in the dataset compiled in this thesis are based on internal combustion (IC) prime mover, for which the emission factor is 0.045 lb/MMBtu, as also shown in table 13.

Table 13: Emission factors for different prime movers for SO_2 emissions from landfill gas.

Prime Mover	Emission factor	Units
Combined cycle combustion turbine part	0.045	lb/MMBtu
Gas turbine	0.045	lb/MMBtu
Steam turbine	0.0006	lb/Mcf
Internal combustion	0.045	lb/MMBtu
Combined cycle steam part	0.045	lb/MMBtu
Combined cycle single shaft	0.045	lb/MMBtu

The approach is illustrated for the ‘Tessman Road’ plant (code: 56113) that uses biomass as fuel. Calculations are performed at the plant level since eGRID 2016 describes the method at the plant level and not at the unit level. In order to confirm whether the calculated values match with those given in the eGRID database, such calculations are first performed at the plant level before moving onto the generator level. Comparisons of the calculated values of adjusted emissions with those obtained from the plant file in eGRID 2016[11], indicate disagreement, as discussed below:

1. For NO_x emissions from landfill gas, an emission factor for flaring of landfill gas, 0.000283 tons per MMBtu, is used.
   - Adjustment = 0.000283 (ton/MMBtu) x 664,775 (heat input in MMBtu) = 188.13 ton.
   - Adjusted emissions = 482.00 tons (Unadjusted emissions from the eGRID 2016 plant file) - 188.13 tons (Adjustment) = 293.83 tons.
   - However, the value in the eGRID 2016 plant file is 463.14 tons

   Thus, for NO_x, the calculated adjusted emission value is different from that given in eGRID 2016. This is because the correct value of emission factor for flaring of landfill gas is 0.0000283 tons per MMBtu[27] instead of 0.000283 tons per MMBtu given in the eGRID 2016 Technical Support Document[16]. This shows that the value in the eGRID 2016 Technical Support Document is off by a factor of 10. Thus, it leads to incorrect calculation of adjusted emission of NO_x for all landfill gas-based generators for which NO_x emission needs to be adjusted. There are a total of 12 plants involving landfill gas-based generators. Using the correct emission factor gives the value of 463.14 tons which matches with the value given in the eGRID 2016 plant file[11].

2. For SO_2 emissions from landfill gas, the emissions factor is 0.045 lb/MMBtu.
   - Adjustment = 0.045 (lb/MMBtu) x 664,775 (heat input in MMBtu) / 2000 = 14.96 tons.
   - Adjusted emissions = 14.96 tons (Unadjusted emissions from the eGRID 2016 plant file) - 14.96 tons (Adjustment) = 0.00 tons.
   - The value in the eGRID 2016 plant file is 11.14 tons.

Thus, the adjusted emissions for SO_2 are zero as per the calculations but non-zero as per UNT16 spreadsheet of eGRID 2016. The calculated value of zero is correct according to the eGRID 2010 Technical Support Document[26], which mentions that SO_2 emissions are assumed to be the same as the flare’s emissions and are, therefore, assigned a value of zero. Also, the calculations performed above using emission factors from eGRID 2016 Technical Support Document given in table 13 lead to same conclusion. Thus, both Technical Support Documents 2010 and 2016 lead to same value of zero for the adjusted emissions for SO_2, however, this calculated value doesn’t match with that given in the UNT16 spreadsheet of eGRID 2016.

Therefore, it is clear that the calculated values for NO_x and SO_2 do not match with the values given in the eGRID 2016[11] plant file.

Chapter 5: Summary and Recommendations

The thesis delivers a comprehensive set of parameters for the electricity generators of power plants within the ERCOT grid. These generators parameters may be used as an input dataset to support electric power system simulation. The generator parameters have been found in this work after suitable calculations for different situations, described in the thesis. Foremost, the thesis discusses the heat rate calculation methods appropriate for different prime mover technologies and plants, giving specific examples throughout. Also, discussed are some special cases of generators that are different than usually observed and thus require careful attention while calculating heat rates. The calculated values of heat rates have been compared to a reference dataset, updated for 2016, in order to verify the results and provide suitable explanations for any observed discrepancies. Thereafter, the thesis establishes the unit commitment generator constraint parameters which are related to various costs associated with running the generators. Finally, it discusses the emissions and emission rate estimates for NO_x, SO_2 and CO_2 describing the calculation methodology with specific examples, which again form a vital component of a comprehensive generator dataset. The need to prepare a new dataset updated for 2018 arises to incorporate the addition/removal of various generators since 2016 and also because the reference dataset does not include the emission and emission rate estimates.

It is recommended that further analysis be considered to better understand the differences observed in the unit commitment generator constraint parameters between Stines 2016 and Webster 2018. The UT 2018 dataset prepared in this thesis should be updated routinely with current versions of the Energy Information Administration's Form EIA-860 dataset and the eGRID dataset to incorporate changes in various generator parameters as well as plant status (e.g., in operation, standby, retired or newly inducted).

Appendix A attached separately as a supplementary excel file

Appendix B: Additional Special Cases

This appendix describes some special cases of generators that were encountered during the study and provides methods to calculate their heat rates.

B.1 NEGATIVE NET GENERATION

If electrical energy consumed by the plant exceeds the gross electricity generation of that plant, negative net generation will result. Such a case may arise when the plant consumes electricity to carry out maintenance or other activities whilst generating a very insignificant amount of electricity such that the electrical energy consumption exceeds the gross electricity generation. In cases such as these involving multiple generation units, an average value is calculated. However, only the following such case was encountered among all the power plants studied.

Example: ‘Power Station 4’plant (code: 52132) has three generators: GEN1, GEN2 and GEN3. For this plant, an average heat rate value is calculated by dividing the total adjusted annual heat input by the annual net generation. The calculation is as follows:

Average heat rate =

Total adjusted annual heat input of (GEN1 + GEN2 + GEN3) /

Total annual net generation of (GEN1 + GEN2 + GEN3)

i.e. (72968 + 0 + 14457) / (21152 – 9034 + 0) = 7.214 MMBtu/MWh.

B.2 SEPARATE REPORTING OF HEAT INPUTS FOR COMBUSTION TURBINE (CT) AND STEAM TURBINE (CA) GENERATORS

Most plants do not report the heat input separately for CA generators. They report the total heat input to CT generators and assign a heat input value of zero to CA generators. In these cases, the average heat rate is calculated for the plant and assigned to the CA and

CT generators. However, a few plants, such as the example below, report the heat input value separately for CA and CT generators. Such plants account for 10% of the total number of combined cycle plants (six out of fifty-nine). They contribute only 5% to the total nameplate capacity of combined cycle plants (1937.2 MW out of 38845.0 MW). For such plants, it is found that the sum of heat inputs in the UNIT spreadsheet of eGRID 2016[11] is equal to the total heat input value reported in the Plant spreadsheet of eGRID 2016[11]. This can be illustrated by looking at the 'Formosa Utility' plant (code: 10554) as shown in table 14 for which sum of heat inputs 'A' for the generators (from UNIT spreadsheet of eGRID 2016) is equal the heat input 'B' for the plant (Plant spreadsheet of eGRID 2016). Therefore, in such cases, the heat rate is calculated as follows:

Heat rate = Sum of all the individual heat inputs for the combined cycle generators divided by sum of annual net generation for the combined cycle generators,

Average Heat rate for each generator from Sr. No. 1 to 10 = A / C = 18946439 / 3677652

= 5.152 MMBtu / MWh.

Table 14: Generator wise heat input and net generation and overall plant heat input for ‘Formosa Utility’ plant (code: 10554).

			UNIT spreadsheet eGRID 2016	GEN spreadsheet eGRID 2016	Plant spreadsheet eGRID 2016
Serial Number	Generator ID	Prime Mover	Unit adjusted annual heat input (MMBtu)	Generator annual net generation (MWh)	Plant adjusted annual heat input (MMBtu)
1	BO3	CT	1874238	169793	18946439 (B)
2	ST3	CA	576499	128722	
3	TBG1	CT	2651372	506634	
4	TBG2	CT	2742901	553341	
5	TBG3	CT	2696093	527841	
6	TBG4	CT	2503782	477143	
7	TBG5	CT	2938804	475744	
8	TBG6	CT	1809753	311008	
9	ST2	CA	576499	285949	
10	ST1	CA	576499	241477	
	Total		18946439 (A)	3677652 (C)	

B.3 THERMALLY INFEASIBLE HEAT RATE VALUE

Heat rate (= Heat input/ Net generation) values less than 1.000 (unitless) are not thermally feasible, because the net generation from a generator cannot be greater than the heat input to that generator. Since 1 MWh = 3.413 MMBtu, the heat rate must be greater than 3.413 (in units of MMBtu / MWh). For example, the individual heat rate calculations for each generator of the 'EG178 facility' plant (code: 56233) yield the following values in table 15:

Table 15: Generator wise individual heat rate for the 'EG178 Facility' plant (code: 56233).

Generator ID	Unit adjusted annual heat input (MMBtu)	Generator annual net generation (MWh)	Individual Heat rate (MMBtu/ MWh)	Average Heat rate (MMBtu/ MWh)
STG	33147	146866	*0.226*	7.716
CT02	3114511	342507	9.093	7.716
CTG1	3363866	354539	9.488	7.716

For Generator ID: STG, the heat rate of 0.226 (MMBtu/MWh) is less than 3.413 (MMBtu/MWh). Therefore, the average heat rate of 7.716 (MMBtu/MWh) is adopted.

Appendix C attached separately as a supplementary word file

Chapter 6: Glossary

The meanings of various technical terms used in the thesis are sourced from the online glossary of U.S. Energy Information Administration[28]. These are as follows:

Generator Nameplate Capacity

The maximum rated output of a generator under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.

Gross Electricity Generation

Gross electricity generation for a generator represents the total amount of electric energy as measured at the generator terminal.

Net Electricity Generation

It is represented by the gross generation minus the electricity consumed internally by the plant (e.g., fuel feed systems, boiler feed pumps, pollution control devices, heat recovery equipment, and other auxiliary loads).

Unadjusted Heat Input

The total amount of heat energy, in MMBtu, consumed by an electric generating unit that combusts fuel.

Adjusted Heat Input

The portion of unadjusted heat input that is used to generate electricity. Its value is equal to the unadjusted heat input minus the heat input that is used as useful thermal energy for heating or cooling purposes.

Heat Rate

Heat Rate (MMBtu/MWh) represents the total adjusted heat content of the fuel consumed (based on the higher heating value, HHV) divided by the net electricity generation. In other words, it is the amount of fuel required to generate one unit of electricity.

Combined Heat and Power Plant (CHP)

A combined heat and power (CHP) plant is a type of generating plant that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes. CHP, also known as cogeneration, can convert energy more efficiently than plants that separately produce heat and electricity.

Prime Mover

The engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly (e.g., photovoltaic solar and fuel cells).

Electric Allocation Factor

Factor which when multiplied with the unadjusted heat input gives the value of adjusted heat input.

List of Abbreviations

BTU	British Thermal Units
CA	Combined Cycle Steam Part
CAMD	Clean Air Markets Division
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
CEMS	Continuous Emissions Monitoring System
CHP	Combined Heat and Power
CS	Combined Cycle Single Shaft
CT	Combined Cycle Combustion Turbine Part
eGRID	Emissions and Generation Resource Integrated Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
GT	Gas Turbine
HRSG	Heat Recovery Steam Generator
IC	Internal Combustion
ISO	Independent System Operator
Lb/lbs	Pound
CH_4	Methane
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt – hours
NG	Natural Gas

N_2O	Nitrous oxide
NOx	Oxides of nitrogen
PM	Particulate Matter
ST	Steam Turbine
SO_2	Sulfur dioxide
Ton/tons	U.S. Ton

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Vita

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