**Nicholas School of the Environment**

**Duke University**

**Energy Systems Modeling**

**ENV 716- Fall 2022**

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**\*Post a question in the Sakai Forum, attend office hours, or send a message to 716ask@duke.edu**

**Assignment # 1**

**Objective:**

This assignment offers opportunities to:

-Practice the development of cost models in excel and its use for the analysis of investment decisions.

-Apply the concepts of **Levelized Cost of Electricity (LCOE)** and **Cost of CO2 Avoidance (COA)**[[1]](#footnote-2)

-Become familiar with coal and natural-gas fired power plants, their environmental emissions control equipment, and economics.

DUE SATURDAY 9/10/2022 at 11:55 PM

**Submission Instructions:**

Please use the Assignment Folder in Sakai to deliver 2 files:

1. An **excel** file with the tables for problem 1: Label this file: LASTNAME+FIRSTNAMEINITIAL+MIDLENAMEINITIAL+A1

The Workbook should contain worksheets labeled Table a, Table b, Table c, including the tables displayed below. The workbook should also contain clearly labeled worksheets that make up the levelized cost models developed for this assignment.

1. A **word** file with answers/tables/comments: Label this file: LASTNAME+FIRSTNAMEINITIAL+MIDLENAMEINITIAL+HW1

Please include anything that you think is relevant to help readers understand what you did.

IMPORTANT:

-All the word files **should contain a brief description of the procedure and excel tools you used to accomplish the work**.

-Also, all inserted tables in the word files should be inserted by choosing the third paste option in word (“Link & Keep Source Formatting”)–this links the tables to the corresponding excel file and makes it easier for any reader to find the corresponding excel tabs-.

-For this and all assignments start with a clean/new file and build your model from scratch.

**Problem Description:**

In this assignment we are interested in taking the perspective of decision makers at an electric power utility in the Western U.S., exploring alternatives to comply with potential new regulations that would limit carbon dioxide emissions from its fossil-fired power plants. Although choosing a compliance strategy requires more analysis than what we can do for this assignment, we will start by building an excel-based model to answer two questions:

1. What are the **LCOE**, and **COA** of the investment strategies being considered **to bring a specific power plant into compliance with environmental regulations**? **Which strategy is preferred** using these two metrics as decision criteria?

2. How do **LCOE** and **COA** change for **different assumptions** about **future natural gas prices**?

If you were conducting a similar analysis for an electric utility, you would have the needed information about extant power plants and the costs and performance of emissions controls or new power plants that can be purchased to retrofit or replace them. But if you were conducting this analysis for a state or federal government, for an environmental NGO, or for academic purposes, you would probably not have access to all that data. In that case, **you could extract information about the power plant in question from eGRID**[[2]](#footnote-3) and about **the costs and performance of possible retrofits and replacement from IECM**[[3]](#footnote-4).

Analyzing investments for a specific power plant:

The Hunter power plant in Emery County (Utah) has been generating electricity for more than **30 years**. With **three boilers**, and **three generators** this plant has **a nameplate power generation capacity** of **1,577.2 megawatts (MW)**. All three units are equipped with **wet lime scrubbers** to **control sulfur-dioxide emissions**[[4]](#footnote-5). In recent years the plant has burned **a mix of subbituminous coal** from the Deer Creek Mine and **bituminous coals** from the Sufco, Westridge and Dug Out mines but the Deer Creek Mine is closing[[5]](#footnote-6) so we will assume that **in the future** all the coal burned at this plant will be **almost identical to the WPC Utah Coal** represented in the IECM model.

To prepare for **compliance with proposed new rules** for fossil-fired power plants, decision makers are exploring two investment strategies to reduce CO2 emissions from the entire power plant:

Investment Strategy # 1: **Retiring** Unit 1/Generator 1 and Unit 2/Generator 2 and **installing** a new **Natural Gas Combined Cycle power plant (NGCC).** This strategy **leaves** Unit 3/Generator 3 as is. The new NGCC plant that would replace the two retiring units has **4 two gas turbines**. **The number of hours** that this NGCC plant will operate is **uncertain** (and an important number for calculating LCOE and COA), so for simplicity it is assumed that **the plant will operate at the capacity factor** that allows **the combined power output** of the **NGCC** and the **remaining Unit 3** from the original plant (we will call this “**Bundle 1**”) to be **equal to the power output of the entire original Hunter power plant as recorded in recent years**.

Investment Strategy # 2: **Retrofitting** Unit 1/Generator 1 with post-combustion amine-based **Carbon Capture and Storage Equipment (CCS)** and **leaving** Units 2 and 3 as they are. To install an amine-based CCS it is necessary to also **install** an **SCR** to reduce NOx emissions.

Task:

**Build your own models to estimate LCOE of the original plant, and the LCOE and COA of investment strategies 1 and 2**. **Make your models flexible so you can conduct analysis under uncertainty**. For dealing with **uncertainty on coal prices**, consider coal prices in **the range 1.32 $/MBtu[[6]](#footnote-7) to 2.5 $/MBtu**. Also **allow prices to increase/decrease by 1 cent increments**. Use a **similar approach for Natural Gas prices** and a price that **potentially could be charged to power plants** for emitting carbon dioxide (CO2) to the atmosphere (i.e., **a CO2 tax**). Please set up your model to have the following **default prices**: **2$/MBtu for coal**, **$3/MBtu for gas**, and **a tax on CO2 of 0$/Ton**.

**Please attempt to build a preliminary version of your excel model, before reading the instructions below**. \*To maximize your opportunities for learning I recommend that you build your model in a new/clean spread-sheet in Excel and try to look very little at the model I presented in class)

Step by step guide to build your model:

1. **(5%) Make sure your model follows best practices.**

Set up a workbook in excel. Have one sheet with instructions, one with constants, one with unit’s conversions. Then create one sheet for each of the following tables, label those sheets Table a, Table b, and Table c. Complete the tables by filling in the necessary values in the blank cells with formulas that are **readable**. Have other sheets for other

1. **(9%) This table shows some information on the three units considered. Please fill the blanks with the outputs from your excel calculations.**

Table a: LCOE for the three units

|  |  |  |  |
| --- | --- | --- | --- |
|  | Unit 1 | Unit 2 | Unit 3 |
| Generator Nameplate Capacity (MW) | 525.0 | 525.0 | 527.2 |
| Net Electrical Output (MW) | 491.7 | 491.7 | 493.4 |
| Net Annual Generation in recent years (MWh)[[7]](#footnote-8) | 2,532,025 | 2,807,809 | 2,954,132 |
| Net Capacity factor (%)[[8]](#footnote-9) | 55.06 | 61.05 | 63.97 |
| Gross Capacity Factor in recent years (%)[[9]](#footnote-10) |  |  |  |
| Net Plant Heat Rate in recent years, HHV (Btu/kWh)[[10]](#footnote-11) | 10,060 | 10,060 | 10,350 |
| Fixed O&M ($M[[11]](#footnote-12)/yr) | 31.21 | 31.21 | 31.29 |
| Variable O&M ($/MWh) Calculated excluding fuel or electricity consumption of baseplant and controls | 1.247 | 1.247 | 1.2726 |
| Fuel Costs ($/MWh) Calculated assuming a price for Coal of $2/MBtu |  |  |  |
| Cost of Electricity ($/MWh) calculated assuming a price for Coal of $2/MBtu and assuming identical operations as in recent years. |  |  |  |
| CO2 emissions rate per unit (tons/MWh)[[12]](#footnote-13) | 1.112 | 1.112 | 1.144 |
| Cost of Electricity ($/MWh) calculated assuming a price for Coal of $2/MBtu and a tax on CO2 emissions of $10/ton and assuming identical operations as in recent years. |  |  |  |

1. **(5%) This table contains information on costs and performance of the units resulting from implementing strategy # 1. We report 2 decimal points and use comma as thousands separator: (For unit 3 we repeat the info from tables above). Please fill in the blanks with the outputs from our model.**

Table b

|  |  |  |
| --- | --- | --- |
|  | NGCC replacing units 1&2 | Unit 3 |
| Capital required ($M) a.k.a TCR or Total Capital Requirement | 846.6 | 0.00 |
| FCF (Fixed Charge Factor) | 0.1128 | N/A |
| Annualized Capital ($M/yr) Calculated |  | 0.00 |
| Net Electrical Output (MW) | 1,180 | 493.4 |
| Gross Capacity Factor (%)[[13]](#footnote-14) | 51.66% |  |
| Net Plant Heat Rate, HHV (Btu/kWh) | 6,777 | 10,350 |
| Fixed O&M ($M/yr) | 15.37 | 31.29 |
| Variable O&M ($/MWh) Calculated excluding fuel or electricity | 0 | 1.2726 |
| Per Unit Fuel Costs ($/MWh) Calculated with coal price = $2/MBTU and an NG price of $3/MBTU |  |  |
| CO2 Emissions (lb/MBtu) | 117.6 | 221.1 |
| CO2 emissions rate (tons/MWh) | 0.3987 | 1.144 |
| Total Annual Cost ($M/yr) |  |  |
| Annual Generation (MWh/yr) |  |  |
| Cost of Electricity ($/MWh) |  |  |
| CO2 emissions rate for Bundle 1 (Tons/MWh) |  | |
| **Cost of Electricity for Bundle 1 ($/MWh)** |  | |

1. **(5%) Here we present the information on costs and performance of Unit #1 when implementing Strategy # 2. We report 2 decimal points and use comma as thousands separator: (For units 2 and 3 the info is the same as in the tables above, but we include it again to calculate the LCOE of the whole “bundle” of plants.**

Table c

|  |  |  |  |
| --- | --- | --- | --- |
|  | Unit 1 retrofitted with CCS | Unit 2 | Unit 3 |
| Capital required for CCS installation if unit 1 was being built with it ($M) | 598.4 | 0.00 | 0.00 |
| FCF = CRF | 0.1128 | NA | NA |
| Retrofit factor[[14]](#footnote-15) | 1.20 | NA | NA |
| Annualized Capital ($M/yr) Calculated | 80.9994 | 0.00 | 0.00 |
| Gross Electrical Output (MWg) Set in IECM | 525 | 525 | 527.2 |
| Net Electrical Output (MW) | 432.6 | 491.70 | 493.40 |
| Gross Capacity Factor (%) (For Unit 1+CCS we assume the same capacity factor as assumed for unit 1 before the retrofit) [[15]](#footnote-16) | 58.78% | 65.19% | 68.35% |
| Net Plant Heat Rate, HHV (Btu/kWh) | 10,060 | 10,060 | 10,350 |
| Fixed O&M ($M/yr) Reported by IECM | 47.07 | 31.21 | 31.29 |
| Variable O&M ($/MWh) Calculated excluding fuel and electricity costs | 8.6571 | 1.247 | 1.2726 |
| Per Unit Fuel Costs ($/MWh) Calculated with coal price = $2/MBtu |  |  |  |
| CO2 emissions rate (lb/MBtu) | 22.13 | 221.10 | 221.10 |
| CO2 emissions rate (tons/MWh) | 0.1266 | 1.112 | 1.144 |
| Net Annual Generation (MWh/yr)[[16]](#footnote-17) |  |  |  |
| Cost of Electricity ($/MWh) |  |  |  |
| CO2 emissions rate for Bundle 2 (Tons/MWh) |  | | |
| **Cost of Electricity for Bundle 2 ($/MWh)** |  | | |

1. **(30%) Compare the LCOE of the two strategies and consider fuel price uncertainty**

Present a excel model that allows a comparison of the two investment alternatives in terms of LCOE. Use your model to provide a short commentary (less than 200 words) on the decision of retrofitting or replacing a coal plant. Support your comment with one graph that shows how one decision may be better than other depending on the fuel prices.

Also, note that the LCOE of a strategy needs to consider the costs and performance of the whole bundle of units/plants. That is, we need to look at the LCOE of the bundle of EGUs when Strategy # 1 or Strategy # 2 are chosen. It would be incorrect to compare the LCOE of the NGCC directly with the LCOE of the CCS retrofitted plant. **The two are not comparable because they have very different emissions and electricity production.**

Note: Keep in mind that although NG prices have been low they could rise in the future. Also allow prices to increase/decrease by 1 cent increments. Use a similar approach for Natural Gas prices and a price that potentially could be charged to power plants for emitting carbon dioxide (CO2) to the atmosphere (i.e., a CO2 tax). Please set up your model to have the following default prices: 2$/MBtu for coal, $3/MBtu for gas, and a tax on CO2 of 0$/Ton.

1. **(16%) Compare the LCOE of the two strategies assuming a Natural Gas price of $5.5/MBtu, a Coal Price of $2/MBtu and uncertainty on the tax on carbon dioxide emissions[[17]](#footnote-18).** Present an excel model that allows a comparison of the two investment alternatives in terms of LCOE by assuming point estimates for fuel prices, but assuming a CO2 emission regulatory regime that imposes a cost of carbon between $0/ton and $100/ton[[18]](#footnote-19).
2. **(20%) Compare the COA of the two strategies assuming a Natural Gas price of $5.5/MBtu and a Coal Price of $2/MBtu**

Find the cost of reducing carbon emissions in $/Tonne (i.e., $/metric ton)[[19]](#footnote-20) of CO2 abated for each strategy. This is found by using the following formula:

Where the reference is the original Hunter plant composed of the three generators without any replacements or retrofits.

1. **(10%) A third strategy that could be considered is replacing Hunter Power Plant with a Nuclear Power Plant. Look at the LCOE provided in the** [**ATB**](https://atb.nrel.gov/electricity/2020/data.php) **and answer:**
   1. Would replacing Hunter with a Nuclear Plant be a good strategy? What is the COA of this strategy?

BONUS

**(10%) A fourth strategy that could be considered is replacing Hunter Power Plant with a utility scale solar power plant + a battery that provide the same electricity. Look at the LCOE provided in the** [**ATB**](https://atb.nrel.gov/electricity/2020/data.php) **and answer:**

* 1. Would replacing Hunter with a Utility scale PV plant be a good idea? Why? Present a spreadsheet.

(10%) For non-EE students. Can you think of any question related to your area of studies concentration or expertise that could be answered with similar analysis to the one conducted here? Provide one spreadsheet with a back on the envelope calculation that is useful for that question.

**OPTIONAL MATERIAL**

The following pages explain how we used eGRID and IECM data to obtain this analysis's necessary information and assumptions. Read this only if you are curious. You do not need to read it to complete this assignment.

The information we retrieved or calculated from eGRID was later entered as an input into IECM to represent the three generating units before any replacements or retrofits**.**

**Detailed description on how we obtained the cost model’s inputs from eGRID:**

1. Get general information about Hunter from eGRID[[20]](#footnote-21):

a. In the PLNT sheet, we use the “find” function (and use “Options”, “Match entire cell contents”, because there is more than 1 power plant with the word “Hunter” in its name), and find that the PLNT sheet, row 10111, has information about the Hunter plant in Utah. Some relevant information is:

Table 1: Subset of plant’s data in eGRID PLNT18

|  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Plant name** | **Plant capacity factor** | **Plant nameplate capacity (MW)** | **Plant total annual heat input (MMBtu)** | **Plant annual net generation (MWh)** | **Plant annual NOx emissions (tons)** | **Plant annual SO2 emissions (tons)** | **Plant annual CO2 emissions (tons)** | **Plant annual CH4 emissions (lbs)** | **Plant annual N2O emissions (lbs)** | **Plant annual CO2 equivalent emissions (tons)** | **Plant annual Hg emissions (lbs)** |
| **PNAME** | **CAPFAC** | **NAMEPCAP** | **PLHTIANT** | **PLNGENAN** | **PLNOXAN** | **PLSO2AN** | **PLCO2AN** | **PLCH4AN** | **PLN2OAN** | **PLCO2EQA** | **PLHGAN** |
| Hunter | 0.6002 | 1,577.2 | 86,611,650 | 8,293,966 | 9,770 | 3,133 | 8,886,354 | 2,079,672 | 302,514 | 8,957,425 | -- |

b. We find that three rows in the GEN18 sheet, have information about the Hunter plant’s generators 1, 2 and 3. Some relevant information is:

Table 2: Subset of generators’ data in GEN18 sheet

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Plant state abbreviation** | **Plant name** | **Generator ID** | **Number of associated boilers** | **Generator status** | **Generator nameplate capacity (MW)** | **Generator capacity factor** | **Generator annual net generation (MWh)** | **Generator ozone season net generation (MWh)** | **Generator year on-line** |
| **PSTATABB** | **PNAME** | **GENID** | **NUMBLR** | **GENSTAT** | **NAMEPCAP** | **CFACT** | **GENNTAN** | **GENNTOZ** | **GENYRONL** |
| UT | Hunter | 1 | 1 | OP | 525.0 | 0.551 | 2,532,025 | 1,255,194 | 1978 |
| UT | Hunter | 2 | 1 | OP | 525.0 | 0.611 | 2,807,809 | 1,209,839 | 1980 |
| UT | Hunter | 3 | 1 | OP | 527.2 | 0.640 | 2,954,132 | 1,212,064 | 1983 |

This data shows that the combined electricity generation from the three electric generating units (EGU or generators) in the Hunter plant in year 2018 was 8,293,966. MWh. This is consistent with the value given for the entire plant in cell AN10111 of the PLNT18sheet.

Here we also see the Capacity Factor CFACT calculated at the generator level by eGRID as CFACT = (PLNGENAN) / (NAMEPCAP \* 8760). However, this value is a bit misleading because it does not account for the difference between Gross and Net generation[[21]](#footnote-22). We will not use this number as the Capacity Factor (CF) input in our model. Instead, we will use IECM’s information and estimate CF as (GENNTAN) / (Max Net Electrical Output (MW) \* 8760), where the Maximum Net Electrical Output is equal to the Maximum Gross Electrical Output (that we take as equal to NAMEPCAP) minus the internal power use by the Base Plant and the environmental controls (such as the *In-Furnace NOx Control* and the *Wet FGD*). If our IECM representation of each electricity generating unit is adequate, this estimate of capacity factor will be precise and will measure how much of the potential of the plant to generate Net electricity is used on average during all hours.

c. We find that three rows in the UNT18 sheet have information about the three units (i.e., boilers) of Hunter. Some relevant information is:

Table 3: Subset of Units’ data in UNT18 eGRID

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Plant name** | **Unit ID** | **Unit bottom and firing type** | **Unit operating hours** | **Unit unadjusted annual heat input (MMBtu)** | **Unit unadjusted annual NOx emissions (tons)** | **Unit unadjusted annual SO2 emissions (tons)** | **Unit unadjusted annual CO2 emissions (tons)** | **Unit SO2 (scrubber) first control device** | **Unit NOx first control device** | **Unit year on-line** |
| **PNAME** | **UNITID** | **BOTFIRTY** | **HRSOP** | **HTIAN** | **NOXAN** | **SO2AN** | **CO2AN** | **SO2CTLDV** | **NOXCTLDV** | **UNTYRONL** |
| Hunter | 1 | TANGENTIAL | 7,233.0 | 25,154,147 | 2,422.1 | 840.8 | 2,580,813.1 | WL | LNC1 | 1978 |
| Hunter | 2 | TANGENTIAL | 8,301.0 | 30,549,497 | 2,975.2 | 1,242.2 | 3,134,381.1 | WL | LNC2 | 1980 |
| Hunter | 3 | WALL | 8,507.0 | 30,908,006 | 4,372.4 | 1,050.4 | 3,171,160.2 | WL | LNBO | 1983 |

This data shows that the three generators have Wet lime flue gas desulfurization unit (WL) equipment to remove SO2 and In Furnace Low NOx Controls (to reduce NOx emissions). We also have information about the boilers Firing Types: two are tangential, one is dry wall.

This data also shows the number of hours each of the boilers operated during the year. If we did not know how much is the Maximum Net Electrical Output of the plant (i.e., if we did not know how much of the plant’s output is consumed internally and not available as a final product to inject to the grid) but had an idea of what was the average loading of the plant when operating, we could use this information to estimate the capacity factor of each Unit. Because the units did not operate at full capacity during the number of hours reported in HRSOP, if we just divided HRSOP by 8760 (or 8784 if it is a leap year) we would be overestimating the capacity factor. To avoid this overestimation we would have to assume a plausible loading value of the generator to estimate CF. For example we could assume that the CF of each generator is equal to 0.8\*(HRSOP/8760). This means we would be assuming that each generator operated at an average of 80% of its nameplate capacity during the HRSOP hours[[22]](#footnote-23). Nevertheless, in this case, we have IECM data to estimate the maximum Net Electricity Output of each unit (called Net Electrical Output in the first row of Table b below) and can use it to estimate the maximum amount of electricity that can be generated by the unit. This maximum generation can be then used to see how it compares with the annual generation reported by eGRID to estimate the capacity factor of each unit.

2. Using eGRID data to represent each generating unit in IECM and obtain their costs and performance information

From the eGRID data we can estimate the fuel costs of each generator and the plant as a whole (after assuming a fuel price, and multiplying by the heat rate). However, to estimate the LCOE of the plant it is also necessary to estimate other variable O&M costs and fixed costs. Also, to evaluate the LCOE and COA of the “bundles” that result from strategy 1 or 2, it is necessary to estimate the capital costs of both an NGCC and a CCS retrofit. To this end we represented the three EGUs of Hunter in IECM to estimate costs and performance before and after any retrofits. We also represented a new NGCC plant.

To learn, please attempt to fill out this table first (without looking at the values given in the three columns) and then look at the values provided and the detailed instructions below and correct any mistakes.

Table 4

|  |  |  |  |
| --- | --- | --- | --- |
|  | Unit1/Gen 1[[23]](#footnote-24) | Unit2 /Gen 2 | Unit3/Gen 3 |
| Generator Nameplate Capacity (MW) reported by eGRID This is entered as Gross Electrical Output (MWg) into IECM\* | 525.0 | 525.0 | 527.2 |
| Net Annual Generation (MWh) reported by eGRID\* | 2,532,025 | 2,807,809 | 2,954,132 |
| Capacity Factor (%) calculated from eGRID[[24]](#footnote-25)\*\* | 55.06% | 61.05% | 63.97% |
| Net Plant Heat Rate, HHV (Btu/KWh) calculated from eGRID\* | 9,934 | 10,880 | 10,462 |
| Steam Cycle Heat Rate, HHV (Btu/KWh) entered into IECM to obtain a Net Plant Heat Rate value close to the one calculated from eGRID. (We take this as the Gross Heat Rate) | 8,280 | 8,280 | 8,510 |
| Net Plant Heat Rate, HHV (Btu/kWh) reported by IECM. This is to be compared with the Net Plant Heat Rate estimated from eGRID. If we chose the right Steam Cycle into IECM the two values should be very close. | 10,060 | 10,060 | 10,350 |

\*From eGRID .

\*\*Verify that you get the same data from eGRID. However, we will not use this Net Heat rate and instead use data from previous years as an input into IECM because data from previous years is more consistent (with Units 1 and 2 which are identical, having the same Net Heat rate).

\*\*\*Verify that you obtain the same number. Please note that as stated before, this value is misleading.

Capital cost information:

Note that IECM assumes the plant modeled is a **new plant** and hence a big proportion of the cost of electricity is due to capital costs. However, since the Hunter plant was completed in year 1983 it is safe to assume that it has been fully amortized and hence capital costs do not need to be included in the Cost of Electricity of the original three units.

This is the data we obtained from IECM about cost and performance of HUNTER as is:

**Information obtained from IECM after making the necessary changes to the plant’s configuration and assumptions to represent each of the three EGUs of HUNTER***.*

Table a

|  |  |  |  |
| --- | --- | --- | --- |
|  | Unit 1 | Unit 2 | Unit 3 |
| Net Electrical Output (MW) Reported by IECM | 491.7 | 491.7 | 493.4 |
| Net Plant Heat Rate, HHV (Btu/KWh) Reported by IECM | 1.006e+4 | 1.006e+4 | 1.035e+4 |
| Gross Plant Heat Rate, HHV (Btu/KWh) Reported by IECM | 9,422 | 9,422 | 9,683 |
| Fixed O&M ($M[[25]](#footnote-26)/yr) Reported by IECM | 31.21 | 31.21 | 31.29 |
| Variable O&M ($/MWh) Calculated **excluding** fuel or electricity consumption of base-plant and controls[[26]](#footnote-27) | 1.247 | 1.247 | 1.2726 |
| CO2 Emissions (lb/MBtu) (From the IECM Stack Diagram in GET RESULTS)[[27]](#footnote-28) | 221.10 | 221.10 | 221.10 |
| CO2 Emissions (Tons/hr) (From the IECM Stack/Flue Gas table in GET RESULTS) | 546.8 | 546.8 | 564.3 |

1. **(5%) This table contains information on costs and performance of the units resulting from implementing strategy # 1. We report 2 decimal points and use comma as thousands separator: (For unit 3 we repeat the info from tables above). Please complete the missing values.**

Table c

|  |  |  |
| --- | --- | --- |
|  | NGCC replacing units 1&2 | Unit 3 |
| Capital required ($M) Reported by IECM as TCR or Total Capital Requirement | 846.6 | 0.00 |
| FCF | 0.1128 | N/A |
| Annualized Capital ($M/yr) Calculated |  | 0.00 |
| Gross Electrical Output (MWg[[28]](#footnote-29)) reported by IECM | 1,212 | 527.2 |
| Net Electrical Output (MW) Reported by IECM | 1,180 | 493.8 |
| Gross Capacity Factor (%) assumed as needed to obtain close to the same electricity generation obtained with the original units reported by eGRID[[29]](#footnote-30) | 51.65% | 68.29% |
| Net Plant Heat Rate, HHV (Btu/kWh) Reported by IECM | 6,777 | 10,350 |
| Gross Plant Heat Rate, HHV (Btu/KWh) Reported by IECM | 6,641 | 9,683 |
| Fixed O&M ($M/yr) Reported by IECM | 15.37 | 31.28 |
| Variable O&M ($/MWh) Calculated excluding fuel or electricity | 0 | 1.2726 |
| Per Unit Fuel Costs ($/MWh) Calculated with coal price = $2/MBTU and an NG price of $3/MBTU |  |  |
| CO2 Emissions (lb/MBtu) (From the IECM Stack Diagram in GET RESULTS for the NGCC and from eGRID for unit 3) | 117.6 | 221.1 |
| CO2 emissions rate (tons/MWh)[[30]](#footnote-31) | 0.3987 | 1.144 |
| Total Annual Cost ($M/yr) |  |  |
| Annual Generation (MWh/yr) |  |  |
| Cost of Electricity ($/MWh) |  |  |
| CO2 emissions rate for Bundle 1 (Tons/MWh) |  | |
| **Cost of Electricity for Bundle 1 ($/MWh)** |  | |

**Here we report the information on costs and performance of Unit #1 when implementing Strategy # 2. We report 2 decimal points and use comma as thousands separator**

Table d

|  |  |  |  |
| --- | --- | --- | --- |
|  | Unit 1 retrofitted with CCS | Unit 2 | Unit 3 |
| Capital required ($M 2017) Reported by IECM[[31]](#footnote-32) | 598.4 | 0.00 | 0.00 |
| FCF[[32]](#footnote-33) | 0.1128 | NA | NA |
| Retrofit factor[[33]](#footnote-34) | 1.20 | NA | NA |
| Annualized Capital ($M/yr) Calculated | 80.9994 | 0.00 | 0.00 |
| Gross Electrical Output (MWg) Set in IECM | 525 | 525 | 527.2 |
| Net Electrical Output (MW) Reported by IECM[[34]](#footnote-35) | 432.6 | 491.70 | 493.40 |
| Capacity Factor (%) (For Unit 1+CCS enter the same capacity factor as assumed for unit 1 before the retrofit) [[35]](#footnote-36) | 58.78% | 65.19% | 68.35% |
| Net Plant Heat Rate, HHV (Btu/kWh) Reported by IECM[[36]](#footnote-37) | 10,060 | 10,060 | 10,350 |
| Gross Plant Heat Rate, HHV (Btu/KWh) Reported by IECM[[37]](#footnote-38) | 9,422 | 9,422 | 9,683 |
| Fixed O&M ($M/yr) Reported by IECM | 47.07 | 31.21 | 31.29 |
| Variable O&M ($/MWh) Calculated from IECM data by excluding fuel and electricity costs | 8.6571 | 1.247 | 1.2726 |
| CO2 emissions rate (lb/MBtu) reported by IECM | 22.13 | 221.10 | 221.10 |
| CO2 emissions rate (tons/MWh) reported by IECM | 0.1266 | 1.112 | 1.144 |

**How to represent Hunter Plant into IECM to obtain costs and environmental performance data.**

**\*It is not required to install and explore IECM but this tutorial is included for those interested in exploring this model useful to retrieve costs and performance of extant and new fossil-fired power plants.**

We will use most of the default IECM assumptions for a Pulverized coal plant to represent Hunter but modified:

-The configuration of each Generator (i.e., controls installed, type of boiler, etc..).

-Name plate capacity

-Efficiency (i.e., heat rate)

-Number of operating hours or capacity factor (IECM assumes generation at full capacity but for a number of operating hours that is less than the 365\*24=8760 hours in a year (or 8784 if it is a leap year))

To characterize each of the three Generators as they are now before being replaced or retrofitted, start three new sessions in IECM (one at a time, for each Generator) and leave all the default values, but change:

-Plant Type🡪Pulverized Coal (PC)

-CONFIGURE SESSION/Plant Design/CombustionControls/NOx Control 🡪 In Furnace Controls

-CONFIGURE SESSION /Plant Design/PostCombustionControls/SO2 Control🡪Wet FGD

-CONFIGURE SESSION/Plant Location/PlantLocationValue🡪 U.S. Southwest region since the state of Utah is located there).

-

-SET PARAMETERS/Base Plant/Base Plant Performance/Gross Electrical Output🡪The name-plate capacity of each generator which is the NAMEPCAP value from the generators sheet (see Table 2 above). You need to remove the tick mark from the “calc” box so you can enter the value.

-SET PARAMETERS/Base Plant/Base Plant Performance/BoylerFiringType🡪Tangential for Units 1 and 2 and Wall for Unit 3 (as shown in the UNT18 sheet in eGRID).

Although eGRID does not include this information, we will also assume that each generator has a Fabric Filter to reduce PM emissions:

-CONFIGURE SESSION/Plant Design/PostCombustionControls/Particulates 🡪 FabricFilter

And that the plant is sub-critical:

-SET PARAMETERS/Base Plant/Base Plant Performance/Unit Type🡪Sub-Critical

And we will assume that the coal used is WPC coal:

-SET PARAMETERS/Fuel/CoalProperties/”Click the top bar to retrieve a coal from the database”/Coal Selection/Name🡪WPC Utah

-SET PARAMETERS/Base Plant/Base Plant Performance/Steam Cycle Heat Rate🡪Enter an appropriate value for this Gross Heat Rate, so the Net Plant Heat Rate reported by IECM (reported in GET RESULTS/Overall Plant/Plant Performance/Net Plant Heat Rate🡪) matches the Net Heat Rate we can calculate for each generator by using the information on the unit’s annual heat input reported in eGRID (HTIAN in UNT18 sheet) and the annual generator electrical output reported in eGRID (GENNTAN in the GEN18 sheet) and properly adjusting the units. For example, for unit 1, if we enter 8,280Btu/kWh for the "Steam Cycle Heat Rate, HHV" the Net Plant Heat Rate, HHV Btu/KWh reported by IECM (GET RESULTS🡪Overall Plant🡪Plant Performance) is 1.006e+4Btu/kWh which matches what we calculate for Unit 1. (it also matches the net heat rate we calculated for Unit 2, i.e. 1.006e+4 Btu/kWh ~10,060Btu/kWh ~10.065). (Note that if we entered any number between 8,277Btu/kWh and 8,284 to the Steam Cycle Heat Rate, that would result in a Net Plant Heat Rate of 1.006e+4 so our choice of 8,280 is a bit arbitrary but ok.) For unit 3 we can enter 8,510 Btu/KWh for the "Steam Cycle Heat Rate, HHV" to get a net plant heat rate similar to the one reported by eGRID.

This section explains how to get the cost data necessary to estimate COE of the three units:

We can get fixed and Variable O&M Costs of each Hunter Generator (base plant and all controls) from GET RESULTS/Overall Plant/Total Cost. Variable costs: These are costs that vary with the amount of electricity generated by each unit. We only want to get the information from IECM on how much is the cost of water, waste disposal, and chemicals for the operation of the emissions controls per unit of electricity generated (because we want to build an excel model where the prices of fuel can be changed). However, IECM reports also the fuel used to operate the plant and the electricity consumed in the operation of the base plant and the emissions controls. Given this there are two ways to get the correct variable costs:

1. To add all the variable costs that are not fuel or electricity from the base plant and controls: e.g to add the Water, lime, and Disposal costs from the BasePlant Boiler, the Solid Waste Disposal cost from the Fabric Filter, and the Reagent, Solid Waste Disposal and Water costs of the Wet FGD.

Note that we do not want to account for the electricity use internal to the plant or the controls because we are accounting for the cost of producing this electricity (at different fuel prices) by using the net heat rate of the plant. If we use the electricity cost of running the controls estimated by IECM we will not be able to change the variable costs for different assumptions of the fuel price.

Cost of electricity calculations:

Note that IECM assumes the plant modeled is a new plant and hence a big proportion of the cost of electricity is due to capital costs. However, since the Hunter plant was completed in year 1983 it is safe that it has been fully amortized and hence capital costs do not need to be included in the Cost of Electricity.

Costs of implementing Strategy # 1:

To get costs and performance of a new NGCC, represent a new NGCC in IECM.When starting a new session in IECM, please select "Natural Gas Comb. Cycle**.** Remember to have 4 turbines instead of 2 (SetParameters/PowerBlock/Gas Turbine Performance/Number of Turbines🡪 4).

You can get Fixed and Variable O&M costs for this plant from GET RESULTS/Overall Plant/TotalCost. Again you want to allow fuel costs to vary with NG prices, so make sure you subtract fuel costs from the variable O&M costs for the Base Plant (Power Block). Account for fuel costs on a separate line in your excel model, multiplying heat rate by electricity generation and NG price. You can assume natural gas prices range from 2 $/MBtu to 12 $/MBtu.

You can get capital costs (TCR) from GET RESULTS/Power Block/Capital Cost. To get annualized capital costs, multiply TCR by a Fixed Charge Factor or modify the default FCF in SET PARAMETERS/Overall Plant/Financing, and then look at the "annualized capital" column in GET RESULTS/Overal Plant/TotalCost

**Costs and environmental effects of implementing strategy # 2**

**To get costs and performance of a CCS retrofit add an Amine System for CO2 capture.**

CAPITAL cost of the CCS equipment

-->GET RESULTS/CO2 Capture/Capital Cost: look at Total Capital Requirement (TCR)

This is the Total Capital needed to install the CCS equipment. To get an annualized quantity (e.g. levelized capital cost) you can multiply TCR by the Fixed Charge Factor (FCF).

(**Please** see how different variables affect FCF by taking a look at SET PARAMETERS/Overall Plant/Financing). Because it costs more to install CCS equipment on an existing plant, than on a new plant it is necessary to inflate the costs of the CCS by a “retrofit factor”. Assume a retrofit factor of 1.2 (i.e. a retrofit installation of CCS costs 20% more than a new installation).

b. O&M cost of the CO2 Capture Equipment

There are at least two places where we can see the O&M cost for the CCS control reported by IECM:

-->GET RESULTS/CO2 Capture/CCS System/O&M Cost tab: look at Total Variable Costs and Total Fixed Costs

or alternatively:

-->GET RESULTS/CO2 Capture/Total Cost: look at Total Annual OM Cost

**Please note that the variable O&M for the CO2 control includes steam and electricity (since both are needed to operate the equipment). However, we will account for this cost by noting that the electricity output of the plant is reduced (while the same amount of coal is being used) so please subtract the costs of electricity and steam reported in the O&M cost for the CO2 Capture.**

CO2 Capture causes a significant energy penalty (e.g. it reduces the amount of electricity available to sell). This can be observed by looking at the plant capacity after it has been retrofitted. You can see the new Net Electrical Output in the GET RESULTS/Overall Plant/Plant Performance

1. COA has not been covered before this assignment is posted. It will be explained on L3. It consists of a single formula provided below. [↑](#footnote-ref-2)
2. Lesson 3 introduces eGRID [↑](#footnote-ref-3)
3. The data from the Integrated Environmental Control Model IECM is provided as part of the problem description so it is not required to install/use IECM to get full credit in this assignment. However, it is very useful to learn how to input eGRID’s information into the IECM model to represent a particular power plant and obtain data on costs and performance not provided in eGRID. You can download the IECM from <http://www.cmu.edu/epp/iecm/>. [↑](#footnote-ref-4)
4. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy\_Sources/EnergyGeneration\_FactSheets/RMP\_GFS\_Hunter.pdf [↑](#footnote-ref-5)
5. http://www.pacificorp.com/about/newsroom/2014nrl/ptcdccm.html [↑](#footnote-ref-6)
6. Coal prices in the U.S. are commonly reported in dollars per million BTU. For example the EIA reports it in $/mmBtu, where the unit mm means 1 thousand times 1 thousand = 1 million. One million Btus are also denoted as MBtu (i.e., “Mega Btus” where M has the standard definition of 1 million. Hence M = m\*m). However, older versions of IECM and a number of energy websites capitalize the units and hence use MMBTU to denote “one million Btu”. When you are not sure about the units of a piece of info reported, then look for alternative sources. Sometimes prices are reported in dollars per short ton ($/ton) along with the specification of the Btu content of that coal. For example, the EIA in its coal markets website reports that coal from Central Appalachia with 12,500 Btu, costed $52.60/short ton in 08/06/17. Because the sulfur content also affects the costs of generating electricity with this coal, it is common to report it as well. [↑](#footnote-ref-7)
7. Based on the reported generation in recent years. [↑](#footnote-ref-8)
8. This is called “Capacity Factor” by the EPA in the eGRID database <https://www.epa.gov/egrid>. It uses the definition provided in class. If you multiply the Net CF by the Name Plate Capacity\*8760, you obtain the net electricity generation. This number can never be 100%, even if the plant operates 100% of the time at full capacity because of the internal electricity use of the plant. [↑](#footnote-ref-9)
9. This number is calculated with a denominator equal to the net power output (MW) times 8760 hours of operation, and the net generation (MWh) in the numerator. This number could be 100% if the plant operates at full loading during 100% of the time. [↑](#footnote-ref-10)
10. Average annual net heat rate varies from year to year depending on the number of start-ups and shutdowns of the power plants and loading level. [↑](#footnote-ref-11)
11. $M means millions of dollars. [↑](#footnote-ref-12)
12. FYI-TMI: we calculated from IECM CO2 emissions (Tons/hr) and IECM Net Electrical Output (MW) [↑](#footnote-ref-13)
13. Here we assume that the NGCC will operate at a capacity factor that will result in the same generation that has been observed by the units it is replacing. Here we assume that unit 3 operates at the same capacity factor as in recent years. [↑](#footnote-ref-14)
14. The capital required data presented on the first line of this table is based on data reported from recent installations and vendors. Because it costs more to install CCS equipment on an existing plant than on a new plant, it is necessary to inflate the costs of the CCS by a “retrofit factor”. Assuming a retrofit factor of 1.2 means that CCS costs 20% more than a new installation. [↑](#footnote-ref-15)
15. This is the true CF obtained as the quotient between Net Annual Generation and (Net Electrical Output\*8760) [↑](#footnote-ref-16)
16. Of course, the Net Annual Generation of Unit 1+CCS is lower than the Net Annual Generation of Unit 1 because the CCS consumes electricity and because we are assuming they operate at the same Gross capacity factor. [↑](#footnote-ref-17)
17. You can read more about fuel prices for electricity generators at <https://www.eia.gov/todayinenergy/detail.php?id=52798> [↑](#footnote-ref-18)
18. You can read more about the social cost of carbon (i.e., SCC) at <https://www.rff.org/publications/explainers/social-cost-carbon-101> [↑](#footnote-ref-19)
19. To convert from one short ton (i.e., “ton”) to a metric ton (i.e., “tonne”) you want to multiply by 0.907185. This is because there are 1 million grams in a tonne (i.e., 1,000 kg), but only 907,184 grams in a short ton (i.e., 2000 pounds of 453.592 grams each). [↑](#footnote-ref-20)
20. Lectures 3 and 4 discuss the use of different excel tools to navigate eGRID (and other large data sets). [↑](#footnote-ref-21)
21. That is, this number is calculated in eGRID by dividing the Power Plant annual net generation (MWh) PLNGENAN by the gross electricity output that could have been obtained from this generator, which is equal to the Generators’s nameplate capacity (MW) NAMECAP, times the number of hours in a year (I,e. 365\*24). As you know, the net generation of the plant is not only the consequence of how many hours the plant operated, but also is a result of the capacity at which the plant can generate net electricity. Even if the plant run at its name plate capacity during 100% of the hours in the year, this eGRID’s calculated Capacity factor would be lower than 1, because some of the gross electrical output of the plant will not be part of its NET output and instead will be consumed internally by the plant (for example, to operate the air emissions control equipment). [↑](#footnote-ref-22)
22. If you are interested, you can explore the validity of this assumption by looking for this plant’s information on hourly operations in the EPA’s Air Program Markets Data (AMPD) at <https://ampd.epa.gov/ampd/> taking into account that AMPD info may only provide gross and not net generation. [↑](#footnote-ref-23)
23. Note that eGRID2018 lists units in ascending order (first unit 1, then unit 2, then unit 3), while it lists generators in descending order (first generator 3, then generator 2, then generator 1) [↑](#footnote-ref-24)
24. Note that eGRID does not provide information on the Net Power Generating Capacity of the Generators and instead provides the Nameplate capacity. In eGRID, Nameplate capacity is used to estimate the Capacity Factor of the Generators. [↑](#footnote-ref-25)
25. $M means millions of dollars. [↑](#footnote-ref-26)
26. See the IECM tutorial below if you are curious about how to estimate variable O&M costs excluding Fuel or Energy Penalty. [↑](#footnote-ref-27)
27. This is a value reported by IECM and hence MBtu means a MegaBtu or one million Btu, the same as mmBtu. [↑](#footnote-ref-28)
28. This is not a typo; MWg is how IECM reports gross output to indicate that this quantity includes all the energy output of the plant, including electricity and steam used internally. [↑](#footnote-ref-29)
29. Although these replacement units could have a different CF we are assuming they will generate roughly what the replaced units used to generate. [↑](#footnote-ref-30)
30. This is calculated using the rate of CO2 emissions in Tons/hr and the Net Electricity Output (in MW/hr). We use the reported rate of CO2 emissions (Tons/hr) provided in GET RESULTS🡪Stack🡪Flue Gas🡪Total Out and the heat rate provided in GET RESULTS🡪 Overall Plant🡪Plant Performance🡪Net Electricity Output. An identical result is obtained if we use the CO2 emissions rate in lbs/MBtu and the Net Heat Rate in Btu/kWh. [↑](#footnote-ref-31)
31. This is the Total Capital Required to install CCS equipment in a new plant with the same characteristics as Unit 1. You can find this by subtracting the Total Capital Required ($M) for a unit without a CCS from the Total Capital Requirement ($M) of a unit with CCS. (This value is found in IECM🡪GET RESULTS/OverallPlant->Cost Summary). To get an annualized quantity (e.g. levelized capital cost) multiply TCR by the Fixed Charge Factor (FCF). [↑](#footnote-ref-32)
32. We assume an FCF of 0.1128 which is consistent with the tax rate, debt/equity ratio, cost of debt, cost of equity, and estimated life time of a new coal plant with CCS as reported in IECM. [↑](#footnote-ref-33)
33. IECM reports the costs of installing a new plant, based on data reported from recent installations and vendors. Because it costs more to install CCS equipment on an existing plant than on a new plant, it is necessary to inflate the costs of the CCS by a “retrofit factor”. Assuming a retrofit factor of 1.2 means that CCS costs 20% more than a new installation. [↑](#footnote-ref-34)
34. CO2 Capture imposes a significant energy penalty (e.g. it reduces the amount of electricity available to sell). This can be observed by looking at the plant capacity after it has been retrofitted. You can see the new Net Electrical Output in the GET RESULTS/Overall Plant/Plant Performance [↑](#footnote-ref-35)
35. This is the true CF obtained as the quotient between Net Annual Generation and (Net Electrical Output\*8760) [↑](#footnote-ref-36)
36. The Net Plant Heat Rate is the amount of energy (in this case, coal, measured in terms of its heat content or Btu) required by the electric generating unit for each MWh of electricity that will be injected to the power grid (for transmission to the substations that will later distribute it to final costumers). If you want to estimate the cost of fuel per MWh you need to use this value. [↑](#footnote-ref-37)
37. The Gross Plant Heat Rate is the amount of energy required by the plant for any unit of gross electrical output. Gross electrical output includes the Net Electricity Output that is injected to the power grid, plus the electricity and steam used for internal operations of the plant. Note that there are two ways to estimate the total amount of fuel used in a year (in Btu): 1) Multiply Gross Plant Heat Rate by Gross Electrical Output, or 2) Multiply Net Plant Heat Rate by Net Electrical Output. The two calculations should be identical if we included all the decimals for each quantity. [↑](#footnote-ref-38)