ENERGY FUTURES
DASHBOARD

# Documentation of Cost Calculations for the Energy Futures Dashboard of the Energy Infrastructure of the Future Study

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## Abstract

This white paper describes the calculations, methodology, and data used for the Energy Futures Dashboard online tool as part of the Energy Infrastructure of the Future (EIoF) study. The study aims to forecast cost and greenhouse gas emissions of future energy infrastructure into 2050 from analyzing historic trends in data coupled with an economic model. Using data that represents unique considerations of various geographic region in the contiguous United States, such as variation in historic cost trends, and proximity of resources to urban centers, renewable resource availability, and energy demand patterns, the EFD calculates projected costs for the user's chosen region within the country.

The cost of future electricity infrastructure is understood by calculating and aggregating the capital expenditure costs and the operations and maintenance costs of a desired generation capacity from a portfolio of generation technologies. The EFD also calculates regional spending on petroleum, natural gas, and coal outside of the electricity sector to put all energy spending in the context of the size of population and economy via regional gross domestic product. This white paper is coupled with others that fully describe the EIoF's methodology and findings: see the EIoF project webpage for all documentation.

Documentation of Cost Calculations for Energy Futures Dashboard, Energy Infrastructure of the Future study, September 2020 (paper 2020.6)

## Contents

## Introduction

The Energy Infrastructure of the Future (EIoF) study seeks to provide a robust understanding of the state of the cost and other impacts of energy infrastructure and consumption in the United States. The flagship product of the EIoF project is the Energy Futures Dashboard (EFD), a user interactive web-based tool that allows users to see the impacts of their choices for three major categories of energy production and use for the year 2050: electricity generation mix, the percentage of light-duty vehicles driven on electricity versus liquid fuels, and the percentage of homes heated by electricity and natural gas. For the purposes of this study, the country is divided into geographic regions established by the EIoF project (see Figure 1). The regional definitions enable us to investigate broad geographical differences in energy infrastructure quantities, costs, regulations, and customers that can be compared to trends for the continental United States. In total, there are 13 regions comprised of one or more states.

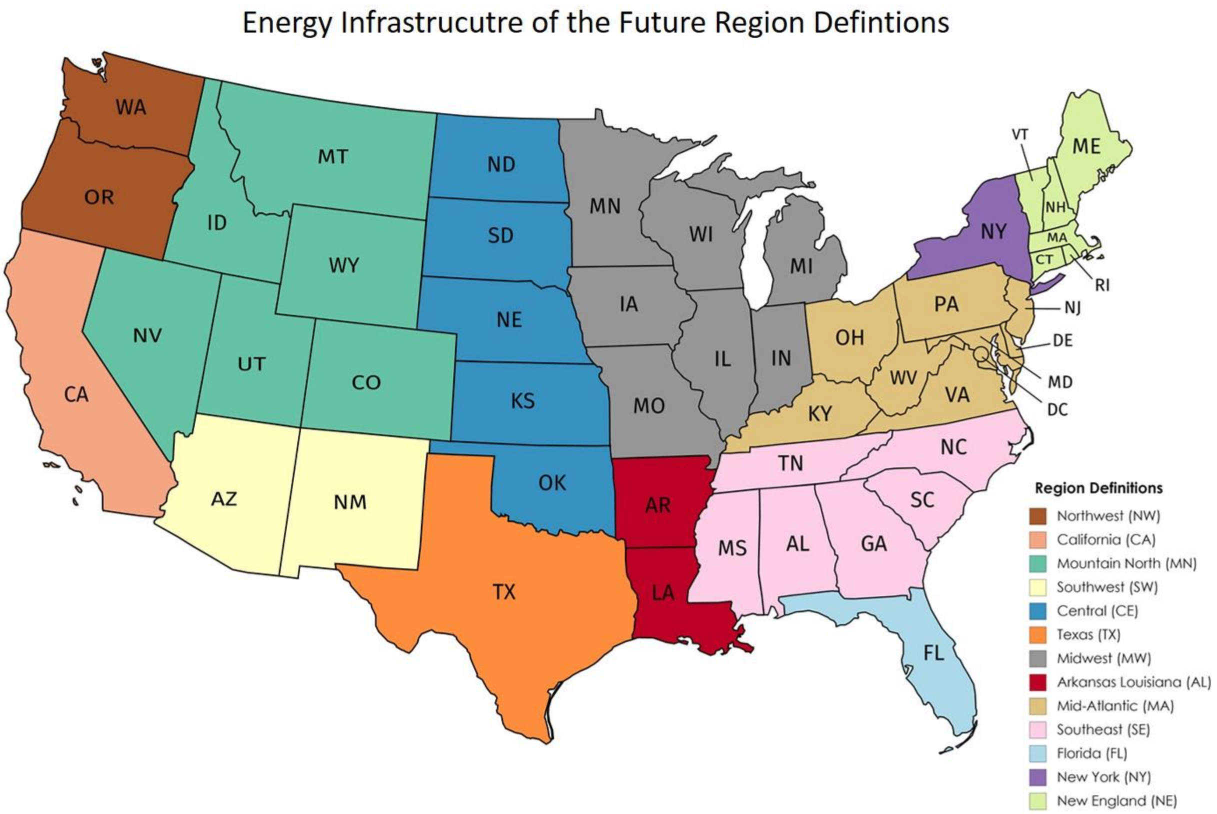

**Figure 1. Regional definitions used for analysis in the Energy Infrastructure of the Future study.**

This white paper summarizes the economic model, built in a Google Sheet workbook, that calculates cost and greenhouse gas projections. The goal of this paper is to document the EFD calculations, the methods for developing the formulas, and their structure in the model.

## Organization of Cash Flow Spreadsheet

The annual cash flow calculations for the EFD online tool are calculated in a Google Sheet document. There is a separate Google Sheet for each EIoF region such that regional-specific parameters can be inserted. In each Google Sheet, we calculate a separate cash flow for each region for the given historical and user's future projected portfolio of energy infrastructure.

The cash flow and cost calculations account for the following major types of energy infrastructure and activities:

- Power Plants
- High voltage transmission power lines
- Low voltage distribution power lines

- Utility-scale batteries

In addition, while the EFD does not estimate spending on oil, gas, and coal infrastructure and activities, the EFD estimates spending on these energy supplies outside of the electricity supply chain as follows:

- Petroleum: spending on petroleum in the industrial, residential, commercial, and transportation sectors
- Natural gas: spending on natural gas in the industrial, residential, commercial, and transportation sectors
- Coal: spending on coal outside of electricity provision (all sectors lumped together)

The future-looking calculations are based on user inputs from the online calculator, set assumptions for each fuel type, and historic trends in values and inflation. The assumptions used in the calculations are organized in the Google Sheet where each fuel and technology type has its own tab of assumptions along with assumptions used to project population and inflation. Below is a list of all of the tabs in the Google Sheet, and the rest of this document summarizes the data and calculations within each tab.

- Manual
  - Summarizes some data sources and calculations for cost and cash flow model
- Inputs
  - This tab initiates the model's calculations by acquiring information from the EFD website as inputs to the Google Sheet.
  - Information being sent:
    - Nameplate Capacity per power plant type, including batteries, in 2050 (MW)
    - Generation output per power plant type in 2050 (TWh)
    - Energy storage capacity for batteries in 2020 (in TWh and MW)
    - Residential Natural Gas Demand in 2050 (quadrillion Btu)
    - Average Miles of Transmission to Connect CSP power plants to load centers (miles)
    - Average Miles of Transmission to Connect wind farms to load centers (miles)
    - Residential NG Consumption - NonSpace Heating, in 2050 (Quad Btu)
    - Residential NG Consumption - Space Heating, in 2050 (Quad BTU)
    - Peak Generation for the region in 2050 (MW)
    - Petroleum fuel used for light-duty vehicle transport (Quad Btu)
    - Average biomass fuel price (2017 USD/MMBtu)
    - Average 2050 geothermal capital expenditures cost (2017 USD/kW)
    - Average 2050 geothermal fixed operating and maintenance cost (2017 USD/kW-yr)

        - Assumed 2020 geothermal capital expenditures cost (2017 USD/kW)
        - Assumed 2020 geothermal fixed operating and maintenance cost (2017 USD/kW-yr)
- Aggregation
    - No new calculations are being made in this tab. This tab aggregates all data that are sent to the EFD website for display to the user.
- Model
    - This tab takes inputs from the “Inputs”, “Assumptions (X)”, and “Inflation GDP Population” tabs, as well as some historic data, to calculate the annual costs and revenues for electricity infrastructure (power plants, transmission, and distribution) from 2000-2050.
- Inflation GDP Population
    - This tab houses data for historical and future assumed population, GDP, and energy prices.
- “Assumptions (X)” where X is represented by the following phrases and each tab defines assumptions and inputs used for the particular type of infrastructure:
    - Natural Gas Non-Electricity
    - T&D (for Transmission and Distribution spending)
    - Coal
    - NG [represents data for natural gas combined cycle and combustion turbine power plants]
    - Wind
    - Solar [for solar photovoltaics]
    - CSP [for concentrating solar power]
    - Nuclear
    - Geothermal
    - Hydroelectric
    - Biomass
    - Petroleum [for petroleum power plants]
    - Battery [assumes lithium ion batteries]

## Data inputs and Calculations: “Inputs” Tab

The cost calculations of the EFD use the inputs as indicated in Table 1.  These data are influenced by the user’s input choices into the EFD, and their derivation is described in this document and the one that describes code “solveGEN.R” that explains the algorithm for dispatching and solving for the required power plant capacity.

**Table 1. The data inputs written into the Google Sheet cost model of the Energy Futures Dashboard. These inputs derive from user choices except for miles of transmission (for CSP and wind) and residential natural gas consumption for non-space heating needs.**

| Electricity Technology or data label | Capacity and Generation needed in 2050 | |
|---|---|---|
| | Nameplate Capacity (MW) | Net Generation (TWh) |
| Coal | | |
| Nuclear | | |
| Natural Gas (CC) | | |
| Natural Gas (CT) | | |
| Hydro | | |
| Solar PV | | |
| Wind | | |
| Geothermal | | |
| Biomass | | |
| Other | | |
| Petroleum | | |
| Storage | | |
| Solar CSP | | |
| Average Miles of Trans. to Connect CSP | | |
| Average Miles of Trans. to Connect Wind | | |
| Residential NG Consumption-NonSpace Heating, 2050 (Quad Btu) | | |
| Residential NG Consumptio -Space Heating, 2050 (Quad Btu) | | |
| Peak Generation in 2050 (MW) | | |
| Petroleum for LDV transport in 2050 (Quad BTU) | | |
| Average biomass fuel price based on ReEDS 2012 supply (2017 USD/MMBtu) | | |
| Average 2050 geothermal CAPEX cost based on ReEDS supply (2017 USD/kW) | | |
| Average 2050 geothermal FOM cost based on ReEDS supply (2017 USD/kW-yr) | | |
| Assumed 2020 geothermal CAPEX cost based on ReEDS supply (2017 USD/kW) | | |
| Assumed 2020 geothermal FOM cost based on ReEDS supply (2017 USD/kW-yr) | | |

## Data inputs and Calculations: "Inflation GDP and Population" Tab

### Regional GDP

We use regional gross domestic product (or gross regional product, GRP) of each of the EIoF regions to display spending on energy relative to this economic metric. The data are aggregated from state data from the Bureau of Economic Analysis time series of nominal gross state product "SAGDP2N Gross domestic product (GDP) by state: All industry total (Millions of current dollars)". We assume all states and regions experience the same inflation rate of the overall U.S. economy and convert these nominal GRP to real GRP using the same U.S. GDP deflator.

**Table 2. Historical nominal gross regional product for each EIoF region.**

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **NW** | 355 | 357 | 369 | 385 | 406 | 440 | 472 | 508 | 521 | 514 | 529 | 550 | 575 | 599 | 631 | 673 | 706 | 751 | 806 | 851 |
| **CA** | 1367 | 1384 | 1436 | 1527 | 1632 | 1754 | 1875 | 1956 | 1991 | 1920 | 1975 | 2050 | 2144 | 2263 | 2395 | 2554 | 2658 | 2819 | 2998 | 3137 |
| **MN** | 405 | 420 | 433 | 453 | 489 | 538 | 581 | 619 | 636 | 609 | 627 | 652 | 668 | 696 | 730 | 762 | 789 | 834 | 886 | 929 |
| **SW** | 220 | 227 | 237 | 256 | 275 | 302 | 326 | 343 | 343 | 326 | 332 | 345 | 356 | 364 | 377 | 388 | 402 | 422 | 449 | 470 |
| **CE** | 274 | 287 | 298 | 316 | 334 | 358 | 386 | 414 | 441 | 425 | 445 | 483 | 511 | 532 | 559 | 556 | 551 | 572 | 603 | 617 |
| **TX** | 739 | 773 | 787 | 830 | 906 | 986 | 1085 | 1179 | 1237 | 1163 | 1237 | 1331 | 1411 | 1502 | 1573 | 1568 | 1566 | 1666 | 1803 | 1887 |
| **MW** | 1693 | 1724 | 1782 | 1854 | 1953 | 2039 | 2116 | 2200 | 2202 | 2165 | 2256 | 2333 | 2432 | 2508 | 2609 | 2706 | 2766 | 2844 | 2973 | 3071 |
| **AL** | 202 | 208 | 213 | 233 | 254 | 287 | 300 | 304 | 314 | 304 | 327 | 335 | 342 | 343 | 356 | 353 | 348 | 363 | 386 | 397 |
| **MA** | 1881 | 1957 | 2032 | 2119 | 2245 | 2372 | 2478 | 2576 | 2643 | 2632 | 2724 | 2813 | 2902 | 2984 | 3092 | 3201 | 3275 | 3367 | 3526 | 3654 |
| **SE** | 1065 | 1102 | 1141 | 1191 | 1269 | 1347 | 1426 | 1476 | 1509 | 1485 | 1522 | 1572 | 1629 | 1685 | 1756 | 1850 | 1918 | 1995 | 2090 | 2180 |
| **FL** | 489 | 517 | 549 | 584 | 636 | 697 | 744 | 769 | 751 | 725 | 738 | 747 | 769 | 801 | 839 | 895 | 939 | 986 | 1039 | 1093 |
| **NY** | 839 | 877 | 887 | 905 | 955 | 1015 | 1071 | 1109 | 1099 | 1153 | 1214 | 1236 | 1322 | 1356 | 1427 | 1488 | 1540 | 1604 | 1669 | 1732 |
| **NE** | 591 | 610 | 627 | 651 | 694 | 725 | 764 | 800 | 813 | 814 | 840 | 858 | 889 | 907 | 934 | 984 | 1011 | 1043 | 1088 | 1136 |

In addition, the "Inputs" tab holds a value for assumed overall future (2020-2050) inflation of 2%/yr that is calculated from historical data as the 2001-2018 average annual change in nominal GDP minus the 2001-2018 average annual change in Real $2012 chained US GDP. The EFD assumes a value for average growth in real GDP of 2%/yr that is the average rate of change from 2001-2018 using chained $2012 data from US BEA National Income and Product Accounts (NIPA) Table 1.1.6 (downloaded December 3, 2019, Last Revised on: November 27, 2019).

Thus, the EFD assumes future (2020-2050) nominal GDP grows at 4%/yr, with inflation and real GDP each growing at 2%/yr.

The economic forecasting is reliant on a projection of GDP per EIOF region. This tab aggregates population and GDP information from the respective states within the EIOF region to calculate percent change in real and nominal values to allow the model to forecast cost into 2015. The calculation for annual percent change in real GDP ($DGDP_{Real}$) is done with Equation (1) where $GDP_{Real,T}$ is the aggregate of all of the states in the region's GDP in year T.

$$DGDP_{Real} = \frac{GDP_{Real,T} - GDP_{Real,T-1}}{GDP_{Real,T-1}} \qquad (1)$$

The calculation for annual percent change in nominal GDP ($DGDP_{Nominal}$) is done with Equation (2) where $GDP_{Nominal,T}$ is the aggregate of all of the states in the region's GDP in year T.

$$DGDP_{Nominal} = \frac{GDP_{Nominal,T} - GDP_{Nominal,T-1}}{GDP_{Nominal,T-1}} \qquad (2)$$

The GDP for each state is inputted using historical data until 2019, then is increased based upon DGDP until 2015 per Equation (3). Population for each EIOF region in year T is the aggregate population of each individual state in the region for every year T.

$$GDP_{Nominal\ and\ Real,T} = (1 + DGDP_{Nominal\ and\ Real,T}) * GDP_{Nominal\ and\ Real,T-1} \qquad (3)$$

## Regional Population

The historical and future population assumptions for each region are described in a separate document entitled "2050 Population and Electricity Customers Projections by EIoF Region."

## Power Plant Capital, Operating and Financing Expenditures

### Power Plant: Capital Expenditures (CAPEX)

The total annual capital expenditure for a **given type** of power plant (e.g., wind farm, natural gas combined cycle, etc.) in any given year (T), $\text{CAPEX}_{\text{TotalPP,T}}$, is a sum of spending on all power plants under construction in that year. The structure of this calculation is shown below in Table 3 and is based on when new capacity is assumed to begin operation. The desired newly installed capacity (NIC) to be brought on in a year T is $\text{NIC}_{\text{T}}$. $\text{NIC}_{\text{T}}$ is constructed over an assumed number of years (n), which differs across plant types. Therefore, construction of the $\text{NIC}_{\text{T}}$ begins in year T-n. For example, if we request 1000 MW of capacity in 2020 and it takes 2 years to build out the capacity, its CAPEX is spent over years 2018 and 2019 such that the power plant is in operation at the beginning of 2020.

Equation (4) shows the CAPEX in year T-n for the $\text{NIC}_{\text{T}}$ power plant capacity that is to begin operation in year T. Each individual CAPEX entry in Table 3 is of the form of Equation (4), and $AveCAPEX_{T\text{-}n}$ represents the average capital cost per unit ($/MW) of the type of power plant of interest in year T-n, such that we can account for assumed changes in capital cost over time.

$$CAPEX_{NIC_T,T-n} = \frac{NIC_T}{n} \cdot AveCAPEX_{T-n} \tag{4}$$

The total annual CAPEX on all power plants of a given type (or of all types) in year T, $\text{CAPEX}_{\text{TotalPP,T}}$, is the sum of the NIC to begin operation in the next n years. Because it takes n years to construct new power plants, $\text{CAPEX}_{\text{TotalPP,T}}$ also potentially includes spending on CAPEX for power plants to come online in years T+1, … T+n-1. Equation (5) defines $\text{CAPEX}_{\text{TotalPP,T}}$, and this equation represents the sum over all rows in Table 3 for a given column representing spending in year T.

$$CAPEX_{TotalPP,T} = \sum_{t=1}^{n} \frac{NIC_{T+t}}{n} \cdot AveCAPEX_T \tag{5}$$

The total CAPEX (over all years of construction) for the NIC to be operational in year T,$CAPEX_{NIC_T}$, is shown in Equation (6). In Table 3, Equation (6) is effectively a sum of columns for a given row.

$$CAPEX_{NIC_T} = \sum_{t=\text{T}-\text{n}}^{T-1} \frac{NIC_T}{n} \cdot AveCAPEX_{T-t} \tag{6}$$

**Table 3. Demonstration of total annual capital expenditures on power plants, $CAPEX_{TotalAnnual,T}$, that would occur in years 2017-2020 for newly installed capacity (NIC) to become operational in 2018, 2019, and 2020. In this example, construction time is assumed as n = 2 years.**

| Year | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| Desired NIC each year | $NIC_{2017}$ = (does not affect calculation) | $NIC_{2018}$ = 100 MW | $NIC_{2019}$ = 1,000 MW | $NIC_{2020}$ = 1,500 MW |
| Each column is an expression of Equation (5), which is a sum of each cell in that column. → | $CAPEX_{TotalPP,2017} = CAPEX_{NIC_{2018},2017} + CAPEX_{NIC_{2019},2017}$ ↓ | $CAPEX_{TotalPP,2018} = CAPEX_{NIC_{2019},2018} + CAPEX_{NIC_{2020},2018}$ ↓ | $CAPEX_{TotalPP,2019} = CAPEX_{NIC_{2020},2019}$ ↓ | |
| CAPEX for NIC to begin operating in year T = 2018, (Equation (4)) $CAPEX_{NIC_{2018}}$ → | $CAPEX_{NIC_{2018},2017} = \frac{NIC_{2018}}{2} \cdot AveCAPEX_{2017}$ | 0 | 0 | |
| CAPEX for NIC to begin operating in year T = 2019, (Equation (4)) $CAPEX_{NIC_{2019}}$ → | $CAPEX_{NIC_{2019},2017} = \frac{NIC_{2019}}{2} \cdot AveCAPEX_{2017}$ | $CAPEX_{NIC_{2019},2018} = \frac{NIC_{2019}}{2} \cdot AveCAPEX_{2018}$ | 0 | |
| CAPEX for NIC to begin operating in year T = 2020, (Equation (4)) $CAPEX_{NIC_{2020}}$ → | 0 | $CAPEX_{NIC_{2020},2018} = \frac{NIC_{2020}}{2} \cdot AveCAPEX_{2018}$ | $CAPEX_{NIC_{2020},2019} = \frac{NIC_{2020}}{2} \cdot AveCAPEX_{2019}$ | |

Table 4 and Table 5 list the values for the financial assumptions used for new construction of each type of power plant in the EFD cost model. Hydropower plants are not listed as the EFD assumes no new hydropower capacity will be installed in the future. We assume that new coal-fired power plants must capture 30% of carbon dioxide ($CO_2$) emissions as in Rhodes *et al.* 2016 and 2017. This assumption makes coal power plants aligned with the EPA's New Source Performance Standards of 635.6 g/kWh $CO_2$ (1400 lb/MWh).

**Table 4. Financial and cost assumptions governing capital expenditures for installing power plants.**

| Technology Type | Share of Debt | Share of Equity | Interest Rate on Debt | Return on Equity | Average Loan Term (years) | Federal Tax Rate (since 2018) |
|---|---|---|---|---|---|---|
| **Coal** | 40% | 60% | 4.75% | 8% | 15 | 21% |
| **Natural Gas CC&CT** | 65% | 35% | 7.5% | 9% | 10 | 21% |
| **Wind (Onshore)** | 60% | 40% | 8% | 12% | 10 | 21% |
| **Solar PV** | 60% | 40% | 8% | 12% | 10 | 21% |
| **Solar CSP** | 60% | 40% | 4.75% | 8% | 15 | 21% |
| **Nuclear** | 40% | 60% | 4.75% | 8% | 15 | 21% |
| **Hydro** | 60% | 40% | 4.75% | 8% | 15 | 21% |
| **Geothermal** | 60% | 40% | 4.75% | 8% | 15 | 21% |
| **Biomass** | 60% | 40% | 4.75% | 8% | 15 | 21% |
| **Petroleum** | 60% | 40% | 4.75% | 8% | 15 | 21% |
| **T&D** | 40% | 60% | 4.75% | 8% | 15 | 21% |
| **Battery** | 20% | 80% | 8% | 12% | 10 | 21% |

**Table 5. Additional financial and cost assumptions for power plants.**

| Technology Type | Installed Cost in 2020, CAPEX ($2018/kW)[a] | MACRS Deprecation (years) | Average Lifetime (years) | Construction Time (years)[b] |
|---|---|---|---|---|
| **Coal** | 5,259 | 20 | 50 | 6 |
| **Natural Gas CC** | 1,108 | 15 | 27 | 3 |
| **Natural Gas CT** | 680 | 15 | 29 | 3 |
| **Wind (Onshore)** | 1,679 | 5 | 26 | 2 |
| **Solar PV** | 1,354 | 5 | 24 | 1 |
| **Solar CSP** | 3,656[c] | 5 | 24 | 3 |
| **Nuclear** | 7,112 | 15 | 35 | 6 |
| **Hydro[d]** | n/a | 15 | 61 | 3 |
| **Geothermal** | See supply curves in section below | 15 | 29 | 3 |
| **Biomass** | 4,322[e] | 15 | 31 | 3 |
| **Petroleum** | 982[f] | 15 | 45 | 3 |
| **Battery[g]** | 260 (299 $2018/kWh) | 7 | 15 | 1 |

a: Installation cost of new power plants each year from 2020-2050 are from NREL Annual Technology Baseline, 2020, "moderate" scenarios unless otherwise specified (NREL, 2020).

b: The assumed number of years for construction per power plant are from (NREL, 2020).

c: The EFD assumes dispatch of CSP without thermal energy storage. Thus, to use cost assumptions from the NREL Annual Technology Baseline, 2020 we 1) we remove the cost of the storage; 2) change the solar multiple from 2.4 to 1.0 (and thus capital cost of building the mirror array decrease by over half). Example: The NREL ATB 2020 reports a CAPEX value for CSP with 10 hours of storage and a solar multiple of 2.4 in year 2020 projected as 6,823 $2018/kW, but when you remove storage costs and change solar multiple to 1.0, the cost is 3,656 $2018/kW.

d: The EFD assumes no new hydropower capacity can be built.

e: Capital cost for a biomass power plant are as listed in NREL ATB 2020 for a "Dedicated" biomass facility (not a coal-fired facility that co-fires with biomass).

f: Cost listed here from EIA AEO 2018 for "Conv Gas/Oil Combined Cycle (CC)" at 982 $/kW as listed in the Electricity Market Module of the National Energy Modeling System: Model Documentation 2018, DOE/EIA-M068.

g: Battery cost outside of parentheses is $2017 per kW of power ouptut capacity. Battery cost inside of parentheses is $2017 per kWh of energy storage capacity.

***Depreciation:***

The annual depreciation for each technology is the accounting treatment of CAPEX as determined by tax laws, which allow only a portion of CAPEX spent in any given year to be treated as tax-deductible once a plant starts operating. Power plant developers use Modified Accelerated Cost Recovery System (MACRS). Each type of plant may have different MACRS schedules ranging from 5 to 20 years (Table 5). Annual depreciation percentages change depending on the number of years but they all add up to 100 percent so that at the end of MACRS schedule, CAPEX of an asset is fully depreciated.

We calculate total depreciation for each year T in two steps. First, we calculate depreciation for the plants that started operation in year T ($NIC_T$). That is, all of their CAPEX has been spent in years T-n through T-1 with n being the construction period, which differs across plant types (Equation (6)). The CAPEX is depreciated over the MACRS schedule applying each year's depreciation percentage from the schedule. In year T, the depreciation rate is the first year in MACRS schedule ($D_1$). Summing up over the MACRS schedule (say, m years, $D_1 \ldots D_m$) will totally depreciate CAPEX of plants that started operating in year T (see Equation (7)).

$$Depreciation_{NIC_T} = \sum_{i=1}^{m} D_i \cdot CAPEX_{NIC_T} \tag{7}$$

However, total depreciation in year T ($Dep_T$) also includes depreciation of plants that started operation in previous years going back to T-m+1. The oldest of these plants will be in their final year of depreciation (m), the next oldest in year m-1 of MACRS schedule, and so on. Second, we sum all these amounts recorded in year T for total depreciation in that year.

***Geothermal Capital Cost Supply Curves:***

We use data from the NREL ReEDS model to create installed capital cost vs supply curves for geothermal electricity as shown in Figure 2 (Brown *et al.*, 2020). Figure 2 includes all types of geothermal resources as considered in the ReEDS model for both binary cycle and flash steam cycle[a] geothermal plant designs: hydrothermal, undiscovered hydrothermal, near-field enhanced geothermal systems (EGS), and deep EGS. We also calculate fixed operating and maintenance (FOM) costs using the data in the ReEDS model. As the user specifies inputs that dictate necessary capacity in 2050 (representing a value on the x-axis of Figure 2), we estimate the 2050 installed cost of geothermal power plants as the capacity-weighted cost from the curves in Figure 2. We assume the 2020 cost of geothermal is the lowest value on each supply curve. Finally, we assume (for simplicity) a linear change in cost from 2020 to 2050 that inherently additionally assumes that geothermal capacity at each point on the supply curve is built at the same rate from 2020 to 2050. That is to say if the lowest cost on the supply curve is $1,000/kW and the user's request dictates 50 GW of geothermal capacity such that the capital cost of the 50th GW is $40,000/kW, then we assume that the plants with CAPEX of $1000/kW are built at the same time and rate as the plants with CAPEX of $40,000/kW.

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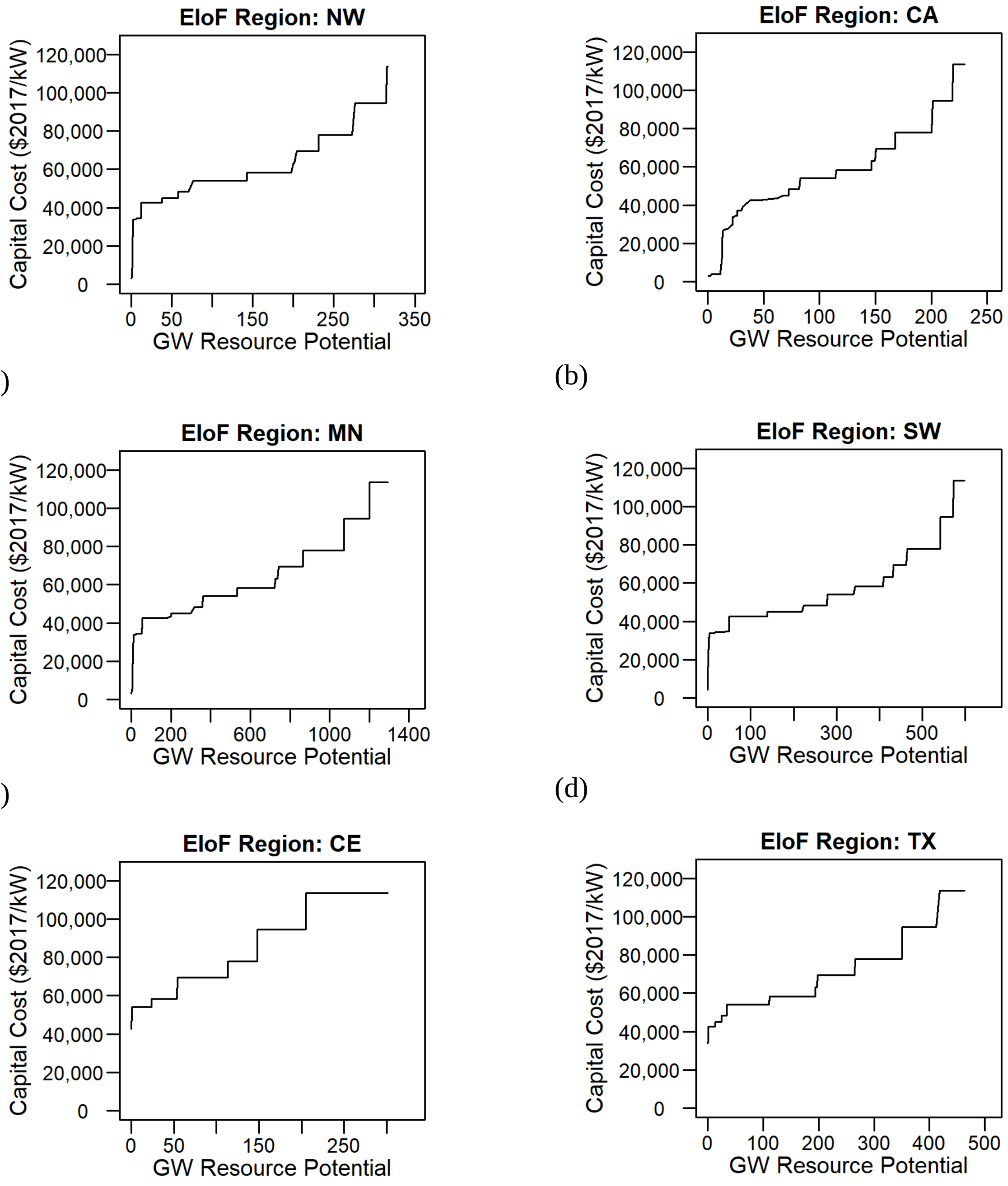
[a] Flash steam plants take high-pressure hot water from deep inside the earth and convert it to steam to drive generator turbines. When the steam cools, it condenses to water and is injected back into the ground to be used again. Most geothermal power plants are flash steam plants.Binary cycle power plants transfer the heat from geothermal hot water to another liquid. The heat causes the second liquid to turn to steam, which is used to drive a generator turbine. (https://www.eia.gov/energyexplained/geothermal/geothermal-power-plants.php)



(a)

(b)

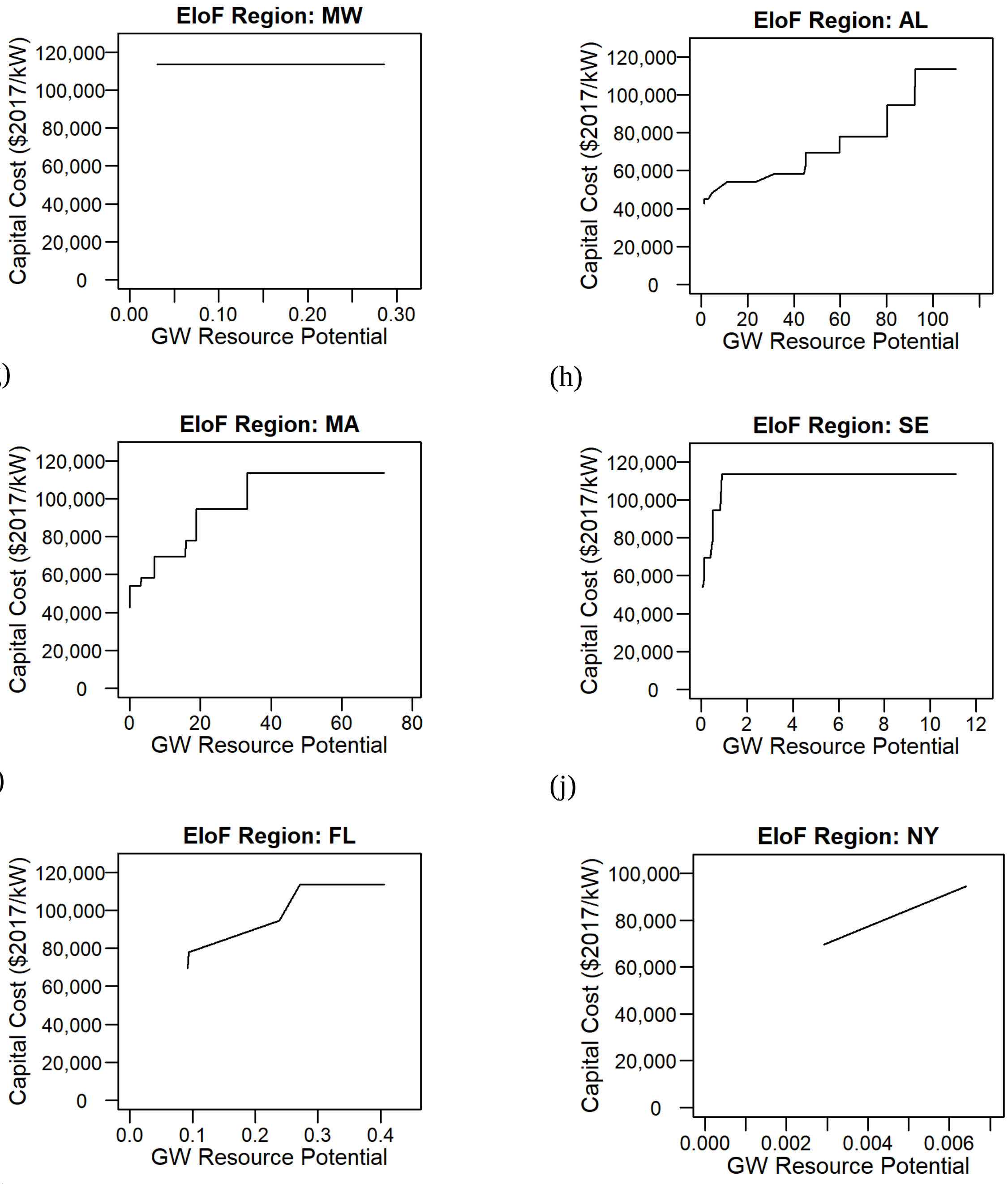
(c)

(d)

(e)

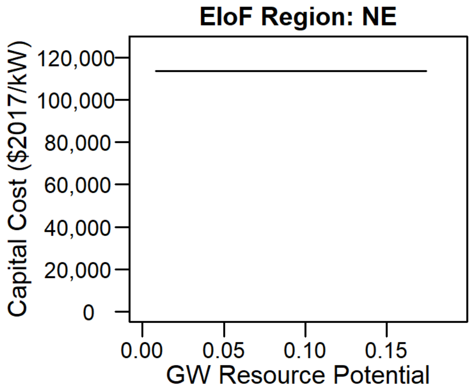
(f)

**Figure 2. Capital cost versus resource supply curves, per EIoF region, for geothermal power plants.**



(g) (h) (i) (j) (k) (l)

**Figure 2. (continued) Capital cost versus resource supply curves, per EIoF region, for geothermal power plants.**



(m)

**Figure 2. (continued) Capital cost versus resource supply curves, per EIoF region, for geothermal power plants.**

## Power Plant: Operating Expenditures (OPEX)

Total annual operating expenses for each type of power plant and battery technology ($OPEX_{PP,T}$) are calculated as the sum of fixed operations and maintenance (FOM), variable operations and maintenance (VOM), and fuel cost (FC) for all electricity-generating infrastructure per year (T) as shown below in Equation (8).

$$OPEX_{PP,T} = FOM_T + VOM_T + FC_T \tag{8}$$

### *Power Plant: Fixed Operations and Maintenance Costs, FOM*

The fixed operations and maintenance (FOM) cost is calculated for each power plant (and battery) technology type using the annual operating capacity in year $T$, $OC_{PP,T}$, and the average FOM ($AvgFOM_{PP,T}$) from each technology. The values used for $AvgFOM_{PP,2020}$ for the base year of 2020 are found in Table 6. For years 2021-2050, for renewable and nuclear technologies we assume the changes in FOM costs from the NREL Annual Technology Baseline 2020, and for fossil fueled power plants we assume the future values from the EIA Annual Energy Outlook 2018.

$$FOM_{PP,T} = OC_{PP,T} * AvgFOM_{PP,T} \tag{9}$$

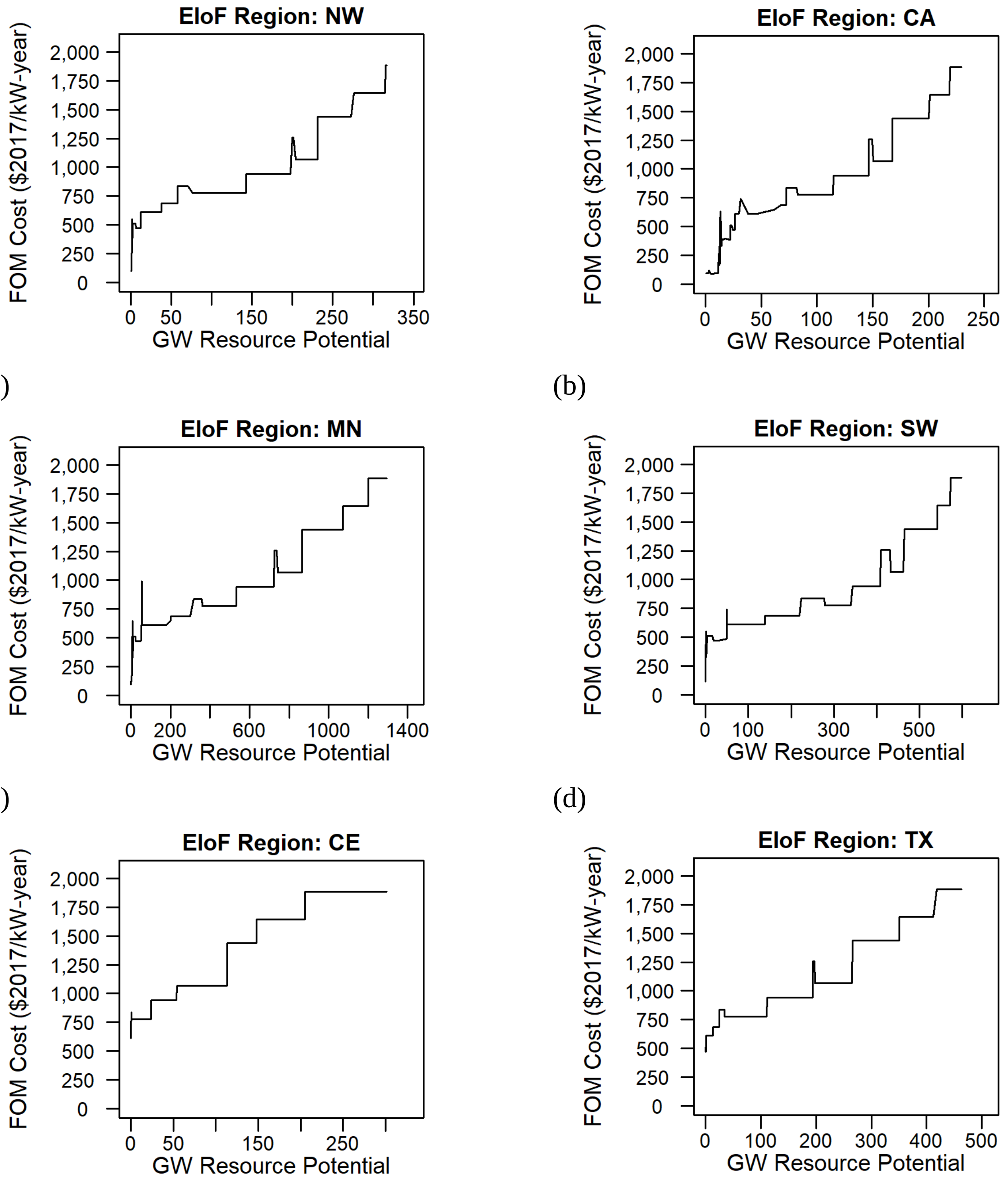
**Table 6. Values for average operating costs, both fixed (FOM) and variable non-fuel (VOM) operating costs for the year 2020.**

| Technology | Average FOM, 2020 ($/MW-yr) | Average VOM, 2020 ($/MWh) |
|---|---|---|
| **Coal (existing)** | 25,000 | 5.50 |
| **Coal (new, 30%CCS)** | 70,700 | 7.17 |
| **Natural Gas (CC)** | 10,100 | 2.02 |
| **Natural Gas (CT)** | 6,870 | 10.81 |
| **Wind** | 43,700 | 0 |
| **Solar PV** | 16,500 | 0 |
| **CSP** | 70,300 | 4.37 |
| **Nuclear** | 101,280 | 2.32 |
| **Hydro** | 40,050 | 1.33 |
| **Geothermal** | See subsection “Geothermal FOM Calculation” | 0 |
| **Biomass** | 112,150 | 5.58 |
| **Petroleum** | 11,110 | 3.54 |
| **Battery (Li-ion)** | See subsection “Battery FOM Calculation” Equations (10) & (11) | 0 |

Source (wind, PV, CSP, geothermal, biomass, and Li-ion battery): NREL Annual Technology Baseline, 2020
Source (hydro, coal, natural gas, and petroleum): EIA AEO 2018
Source (nuclear): FOM and VOM (NEI, 2019), heat rate (NREL ATB 2020)

### *Geothermal FOM Calculation*

Geothermal FOM costs are a function of the total capacity of installed geothermal power and are derived from the NREL ReEDS input assumptions. We set the FOM cost in 2020 based on historical installed geothermal capacity, and we set the 2050 FOM cost based on the quantity of geothermal capacity estimated as required to meet the user’s input criteria. In a similar manner as calculating the geothermal capital cost, as the user specifies inputs that dictate necessary capacity in 2050 (representing a value on the x-axis of Figure 3), we estimate the 2050 FOM cost of geothermal power plants as the capacity-weighted cost from the curves in Figure 3. The FOM cost for each year from 2021 to 2049 is a linear interpolation between the 2020 and 2050 costs.



(a)

(b)

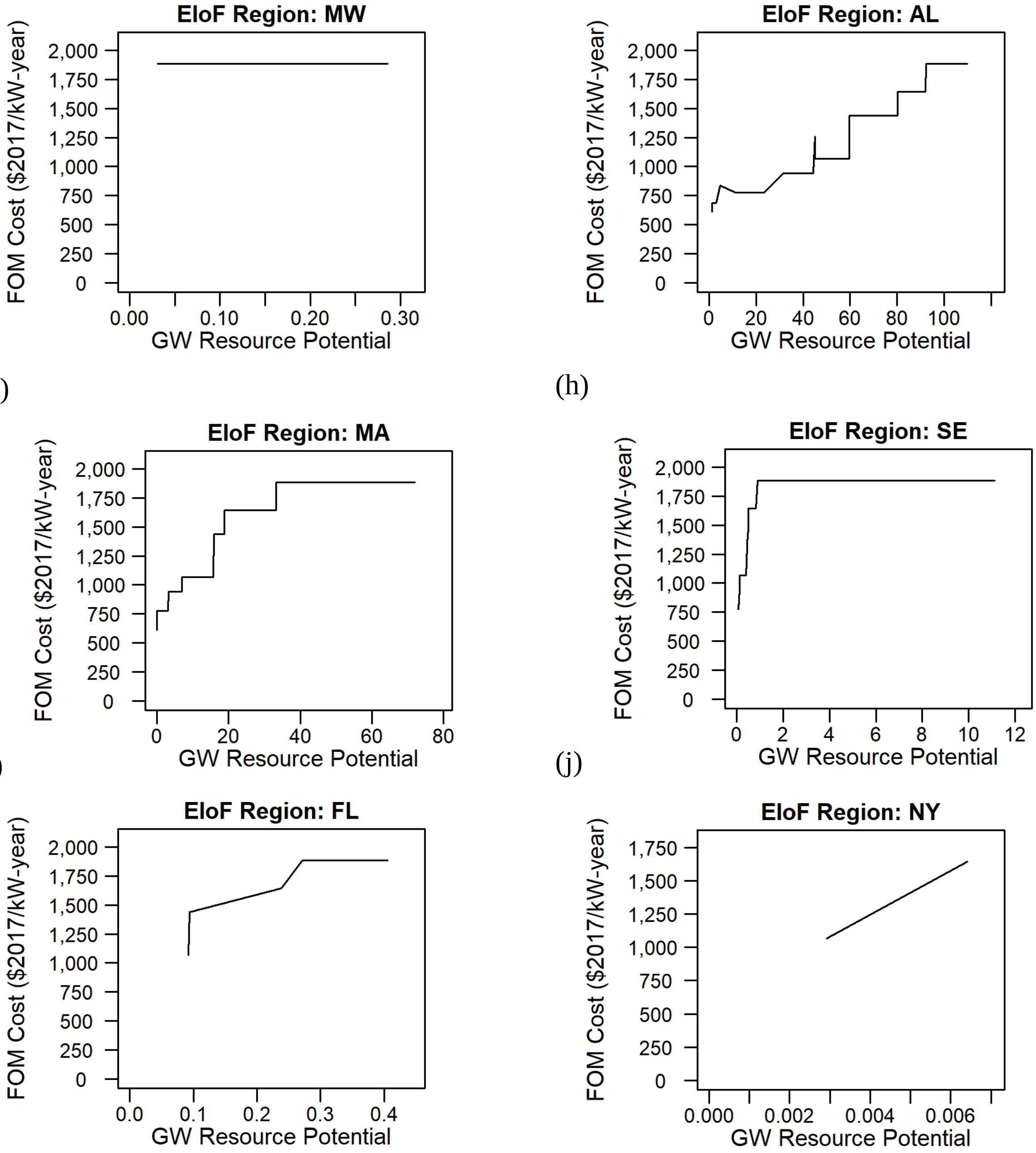
(c)

(d)

(e)

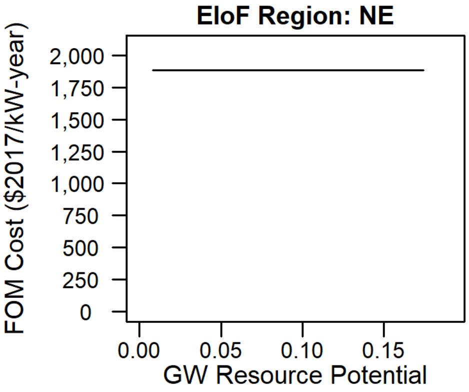
(f)

**Figure 3. Fixed operating and maintenance (FOM) cost versus resource supply curves, per EIoF region, for geothermal power plants.**



(g) (h) (i) (j) (k) (l)

**Figure 3. (continued) FOM cost versus resource supply curves, per EIoF region, for geothermal power plants.**



(m)

**Figure 3. (continued) FOM versus resource supply curves, per EIoF region, for geothermal power plants.**

### *Battery FOM Calculation:*

We follow NREL's ReEDS model, which follows Cole and Frazier (2020), for operating costs of lithium-ion batteries (NREL, 2020). VOM costs are assumed $0/MWh. Li-ion battery FOM costs are summarized as "The FOM value selected is 2.5% of the $/kW capacity cost for a 4-hour battery. We assume that this FOM is consistent with providing approximately one cycle per day. If the battery is operating at a much higher rate of cycling, then this FOM value might not be sufficient to counteract degradation." (Cole and Frazier, 2020) We copy this method and assume FOM costs are 2.5% of the total amount of storage capacity that exists (in any given year) times the current installed capacity costs for that year, scaled to a per kW basis, as if all capacity was built in that year, *T*. Equation (10) describes the FOM cost calculation (in units $/MW-yr) for lithium-ion batteries in year *T* as 2.5% of the per MW battery capital cost, $CAPEX_{\$/MW,battery,T}$ as if all of the battery capacity was installed in year *T*. The total $CAPEX_{\$/MW,battery,T}$ is an addition of the capital cost for installed *power* capacity, $C_{\$/MW,battery,T}$, plus the installed *energy* capacity, $C_{\$/MWh,battery,T}$. multiplied by the number of hours of energy storage at full power capacity, $HrsStorage_{battery,T}$. Equation (11) shows that total annual operating costs for batteries (in unites of $), $OPEX_{battery,T}$, is the FOM cost multiplied by the installed power capacity of the battery, $IC_{MW,battery,T}$.

$$FOM_{battery,T} = 0.025(CAPEX_{\frac{\$}{MW},battery,T})$$

$$FOM_{battery,T} = 0.025\left(C_{\frac{\$}{MW},battery,T} + HrsStorage_{battery,T} \cdot C_{\frac{\$}{MWh},battery,T}\right) \quad (10)$$

$$OPEX_{battery,T} = FOM_{battery,T} \cdot IC_{MW,battery,T} \qquad (11)$$

With regard to battery cycling, this EFD project assumes an extreme case (that is very unlikely to describe lithium-ion battery use during the next decade or two) of batteries that would cycle likely much less than once per day and closer to one full cycle per year. This low cycling rate derives from the EFD "with storage" assumption that excess wind and solar are charged in any hour there is negative net load, and then the power is discharged at the remaining highest net load hours up to the possible level of the rated power capacity in MW. This assumption dictates that there are several months of the year in which there is net charging and several months of net discharging. By assumption, the battery only reaches each of the states of full charge and full discharge one day per year, with all other days at some intermediate level of charge.

As an example battery OPEX cost calculation, consider some year with lithium-ion battery storage at 1,000 MW power capacity and 10,000 MWh energy storage capacity (i.e., 10 hrs of storage) with an installed capital cost (if installed during that same year) of $100,000/MW and $150,000/MWh, respectively. The total FOM cost is = 0.025($100,000/MW + 10 hrs × $150,000/MWh) = 40,000 $/MW-yr. The total annual OPEX for the battery is thus = 40,000 × 1,000 MW = $40 million.

### *Power Plant: Variable Operations and Maintenance Costs (non-fuel), VOM*

The variable operations and maintenance (VOM) cost is calculated for each power plant technology type using the annual generation in year *T* ($Gen_{PP,T}$) and the average VOM from each technology($AvgVOM_{PP,T}$). The values used for average VOM for the base year of 2020 are found in Table 6.

$$VOM_{PP,T} = Gen_{PP,T} * AvgVOM_{PP,T} \qquad (12)$$

### *Power Plant: Fuel Costs*

Annual Fuel costs for Coal, Natural Gas, and Petroleum power plants ($FC_{PP,T}$) are calculated using Equation (13) where $Gen_T$ is generation for year $T$, $HR_{PP,T}$ is the heat rate for the power plant in year T in MMBtu/MWh, and $AvgP_{fuel,T}$ is the average price for that fuel type for year *T* in $/BTU.

$$FC_{PP,T} = Gen_{PP,T} * HR_{PP,T} * AvgP_{fuel,T} \qquad (13)$$

Data for fuel prices are assumed as follows and displayed in Table 7 for the year 2020. The historical data (2000-2019) for average price for natural gas and coal consumed at electric generating plants are from "Table 9.9 Cost of Fossil-Fuel Receipts at Electric Generating Plants" in the EIA's Monthly/Annual Energy Review. For future years (2020-2050) data are from the NREL Annual Technology Baseline 2020 input as real dollars and converted to nominal as needed per inflation assumptions within the EFD. The future price for petroleum power plants is assumed as the distillate fuel oil (PRC000:nom_E_Distillate) price to electricity sector ($/MMBtu) from Table 3 of the EIA AEO 2019 reference case scenario. The average price for uranium for nuclear power plants is assumed constant in real dollar value with nominal cost (shown for 2020 in Table 7) that increases with general inflation.

**Table 7. Fuel costs for each generation technology for year 2020.**

| **Fuel** | **Fuel cost, 2020 ($2017/MMBtu)** | **Fuel cost, 2020 ($nominal/MWh)** | **Average Heat Rate, 2020 (MMBtu/MWh)[c]** |
|---|---|---|---|
| **Natural Gas Combined Cycle (NGCC)** | 2.54 | -- | 7.220 |
| **Natural Gas Combustion Turbine (NGCT)** | 2.54 | -- | 10.370 |
| **Coal (existing)** | 2.04 | -- | 10.100 |
| **Coal (new, 30% CCS)** | 2.04 | -- | 9.750 |
| **Petroleum (DFO)[a]** | 22.0 | -- | 10.600 |
| **Nuclear (Uranium fuel)[b]** | -- | 6.91 | 10.460 |
| **Biomass** | see supply curves in Figure 4 | n/a | 8.760 |

a: Distillate fuel oil (DFO) price delivered to power plants. Source EIA AEO 2019 reference case, Table 3, listed in units of $2018/MMBtu.

b: uranium fuel price in nominal dollars from NEI (2019) was 6.44 $/MWh (nominal dollars) in year 2017.

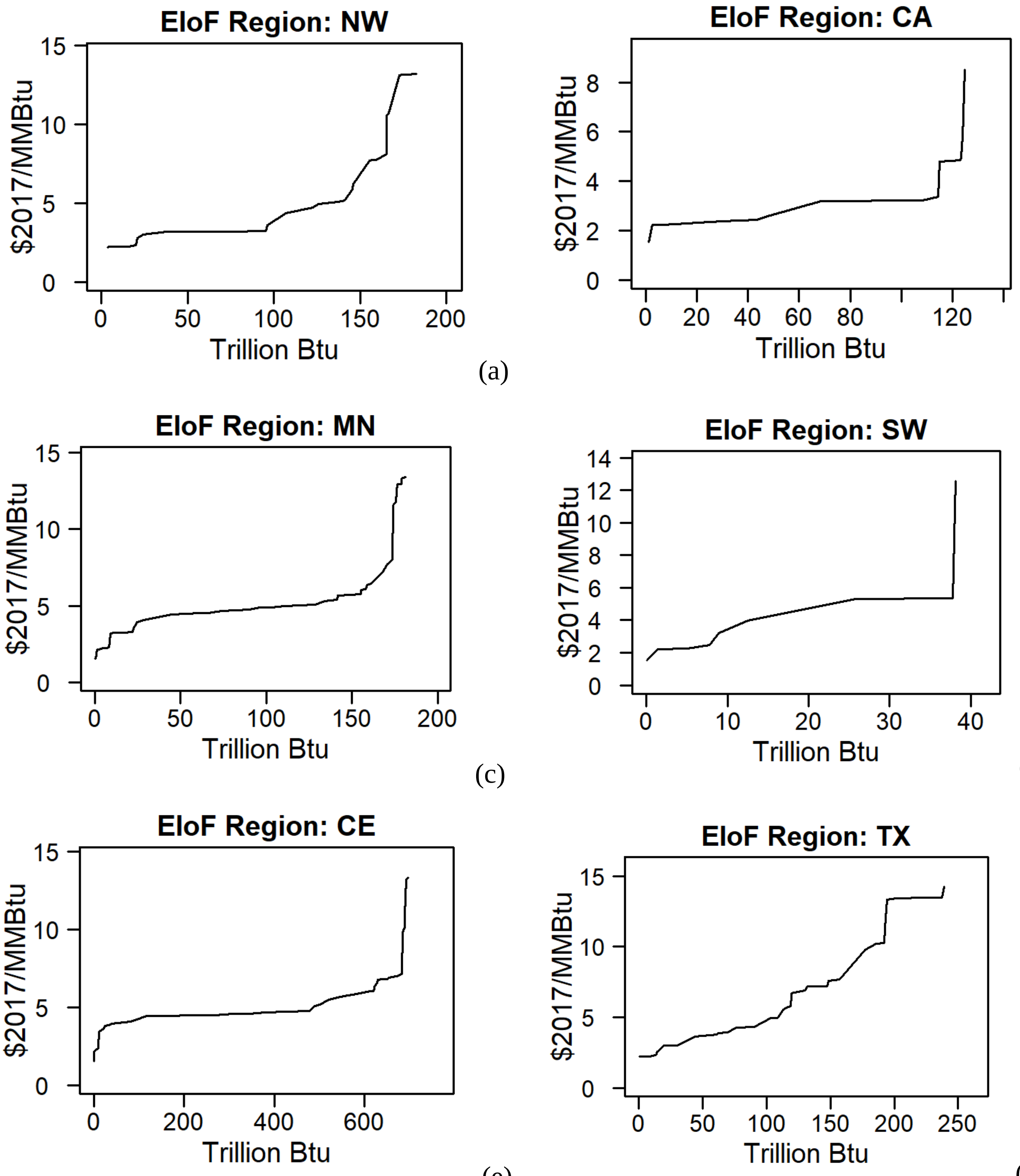
c; Heat rate data for biomass and nuclear: NREL Annual Technology Baseline, 2020. Heat rate data for new coal, all natural gas (NGCC and NGCT), and petroleum are from EIA AEO 2019 reference case.

The heat rate for coal prior to year 2020 is found with historical data. The heat rate for coal post 2020 is found by averaging the heat rate from existing capacity (that installed before 2020 and not yet retired) and new capacity installed after 2020 per the user's inputs.

The fuel cost for nuclear power generation in year $T$ is calculated with Equation (14) where $Gen_{nuclear,T}$ is generation in year $T$, and $AvgP_{nuclear,T}$ is the annual fuel cost in (\$/MWh). $AvgP_{nuclear,T}$ is from the NEI nuclear costs report (NEI, 2019) and assumed constant in real dollars across all years.

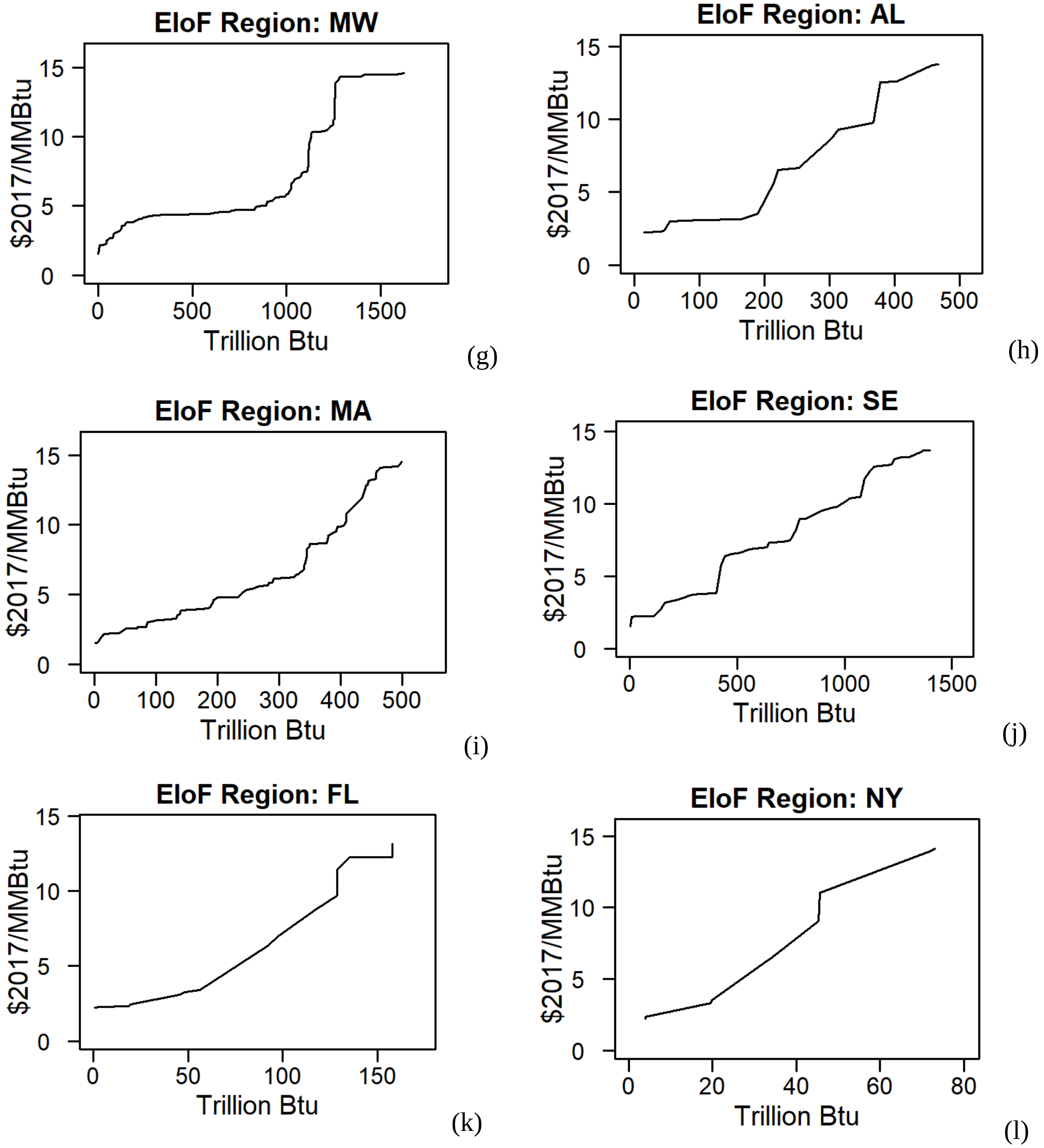
$$FC_{nuclear,T} = Gen_{nuclear,T} * AvgP_{nuclearT} \tag{14}$$

Fuel costs and supply for biomass derive from the NREL ReEDS model input data as aggregated into the 13 EIoF regions as shown in Figure 4. We then assume the average heat rate of biomass power plants to convert fuel costs, in $2017/MMBtu, into VOM costs for biomass power plants in nominal units of $/MWh.



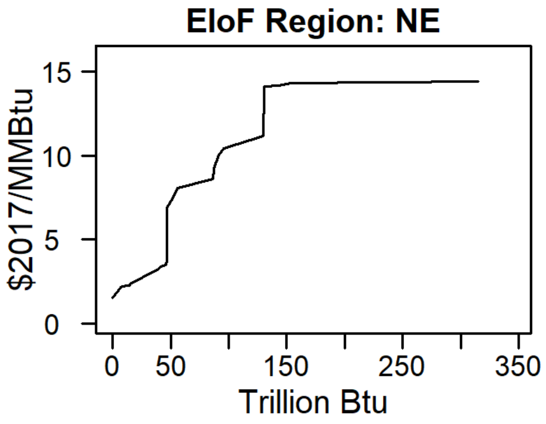
(a) (b) (c) (d) (e) (f)

**Figure 4. Price versus supply curves, per EIoF region, for fuel into biomass power plants.**



(g) (h) (i) (j) (k) (l)

**Figure 4. (continued) Price versus supply curves, per EIoF region, for fuel into biomass power plants.**



(m)

**Figure 4. (continued) Price versus supply curves, per EIoF region, for fuel into biomass power plants.**

## Power Plant: Financing Costs

### *Debt:*

Equation (15) shows the amount of $Debt_{PP}$ borrowed to build the quantity of $NIC_T$ in year $T$ for power plant type $PP$ where $AveCAPEXperMW_t$ is the average cost, dollars per MW, for building power plants of a given type over the n years of construction before year $T$ and $ShareCAPEX_{PP,debt}$ is the fraction of total CAPEX spending on the $NIC_T$ that was borrowed (Table 4).

$$\begin{aligned} Debt_{PP} &= ShareCAPEX_{PP,debt} \cdot NIC_T \cdot AveCAPEX \\ &= ShareCAPEX_{PP,debt} \cdot NIC_T \cdot \left( \frac{1}{n} \sum_{t=1}^{n} AveCAPEXperMW_t \right) \end{aligned} \quad (15)$$

### *Equity:*

The rest of CAPEX not funded via debt is assumed funded by equity of owners (Table 4). Thus, the fraction (1 – $ShareCAPEX_{PP,debt}$) of CAPEX on $NIC_T$ is funded by equity in the power plants. This calculation is shown in Equation (16).

$$Equity_{PP} = NIC_T \cdot AveCAPEX \cdot (1 - ShareCAPEX_{PP,debt}) \quad (16)$$

***Principal:***

The annual principal payment for each technology is the payment made on debt (e.g., a bank loan) that reduces the total amount owed. We calculate principal payments for each year (T) for each technology. The Google Sheet uses the PPMT function to calculate the principal payment owed each year. The PPMT function inputs are the interest rate (*i*), payment period, or year, of interest during the loan period (per), average loan term in years (*nper*), and the amount of money borrowed, or debt (in dollars) to pay for the power plant capital expenditure ($Debt_{PP}$) (Equation (17)).

$$Principal_{T,nper} = PPMT(i, per, nper, Debt_{PP})_T \tag{17}$$

The total principal payment for new installed capacity in year *T*, $NIC_T$, is the sum of all the individual payments made over the loan period. For the $NIC_T$ the principal payments are made over the *nper* years from *T* to *T+nper-1*. For each type of power plant, the total principal payment in year *T* is the sum of all principal payments in year T that pay off debt borrowed for all *NIC* that started operation in previous years *T-nper+1* to *T*.

***Interest:***

The annual interest payment for each technology is the cost of borrowing (debt) for capital expenditures on energy infrastructure. We calculate interest payments for each year (*T*) for each technology. The Google Sheet uses the IPMT function to calculate the interest payment owed each year. The IPMT function inputs are the interest rate (*i*), payment period, or year, of interest during the loan period (per), average loan term in years (*nper*), and the amount of money borrowed, or debt (in dollars) to pay for the power plant capital expenditure ($Debt_{PP}$) (Equation (18)).

$$Interest_{T,nper} = IPMT(i, per, nper, Debt_{PP})_T \tag{18}$$

The total interest payment for new installed capacity in year *T*, $NIC_T$, is the sum of all the individual payments made over the loan period. For the *NIC* installed in year *T*, $NIC_T$, the interest payments are made over the *nper* years from *T* to *T+nper-1*. For each type of power plant, the total interest payment in year *T* ($Int_T$) is the sum of all interest payments in year *T* that pay off debt borrowed for all *NIC* that started operation in years *T-nper+1* to *T*.

## Electricity Grid Transmission, Distribution & Administration Costs

The cost of electric grid transmission, distribution, and administration (TD&A) are calculated uniquely for each of the 13 EIoF regions. The data that inform the TD&A costs originate from the Federal Energy Regulatory Commission Form 1 (FERC, 2018) as collected and discussed by Fares and King (2017). FERC Form 1 data are reported in nominal dollars, but the EFD converts the data to real $2017, as indexed to a general consumer price index.

Fares and King (2017) previously summarized the FERC Form 1 data submitted by regulated investor-owned utilities (IOUs) into three overall categories of transmission, distribution, and administration. The latter category represents the general costs of operating the utility. Here we separately estimate both capital expenditures (CAPEX) and operation and maintenance (OPEX) for two categories: *transmission*; *distribution plus the cost of administration*. We lump together distribution and administration costs since the two categories are highly correlated, and we gain little accuracy by treating them separately.

## **Transmission, Distribution, and Administration Costs – Historical (2000-2016):**

While IOUs submit data to FERC Form 1, the vast majority of municipal utilities and cooperatives do not submit data via FERC Form 1. Thus, a large percentage (20%-40%) of TD&A spending is not reported in FERC Form 1. Also, the number of electricity customers reported in FERC Form 1 ("FERC Form 1 customers") is less than the total number of electricity customers for any given EIoF region. We leverage other data sources to scale up spending levels from FERC Form 1 to estimate spending within the entire TD&A system.

Fares and King (2017) showed that each of the following three variables were highly correlated to real utility spending on CAPEX and OPEX: peak power demand (e.g., peak TW), annual electricity generation (e.g., MWh), and number of customers. We use all three variables to estimate historical spending on TD&A for all electricity and customers in each EIoF region from 2000-2016. First, we use data reported in EIA Form 861 ("EIA-861 customers") as the estimate of 100% of electricity customers per state, and thus aggregated to EIoF region. For each year, $T$, this provides a ratio of the total number of electricity customers (industrial, commercial, and residential) reported in EIA Form 861 to the number of electricity customers reported in FERC Form 1, $R_{EIA/FERC,T}$ (see Equation (19)). We note that the total number of customers is dominated by the number of residential customers.

$$R_{EIA/FERC,T} = \frac{\text{EIA-861 customers}_T}{\text{FERC Form 1 customers}_T} \tag{19}$$

Next, we estimate historical (2000-2016) annual TD&A spending in region $R$ in year $T$ by multiplying the costs reported in FERC Form 1 data by the $R_{EIA/FERC,T}$ ratio as in Equations (20) - (23).

$$CAPEX_{R,T,transmission} = R_{EIA/FERC,T} \times CAPEX_{R,FERC\ 1,transmission} \tag{20}$$

$$OPEX_{R,T,transmission} = R_{EIA/FERC,T} \times OPEX_{R,FERC\ 1,transmission} \tag{21}$$

$$CAPEX_{R,T,dist.\&\ admin} = R_{EIA/FERC,T} \times CAPEX_{R,FERC\ 1,dist.\&\ admin} \tag{22}$$

$$OPEX_{R,T} = R_{EIA/FERC,T} \times OPEX_{R,FERC\ 1,dist.\&\ admin} \tag{23}$$

## Transmission, Distribution, and Administration Costs – Future CAPEX (2017-2050):

Because we have only analyzed FERC Form 1 data through 2016, we separately estimate data for 2017-2020 before linear interpolating to the results driven by the user's desired choices to the year 2050. We estimate annual regional future capital expenditures (CAPEX) for both transmission and distribution + administration as a function of the peak power demand, $P_{peak,R,T}$, estimated for each EIoF region. For region $R$ and year $T$, we use Equation (24) to calculate the annual CAPEX for transmission and Equation (25) to calculate annual CAPEX for distribution and administration. Each equation uses a coefficient, $a_{CAPEX,R}$, with units of $2017 billion/TW, to multiply by the estimated peak power generation for the year, and each $a_{CAPEX,R}$ is specific to a region. This coefficient explains "traditional" capital expenditures to serve load and connect generation. We first explain the calculation of this coefficient in Equation (24) before explaining the two additional cost factors that are calculated in Equations (26) and (27) and associated with additional transmission expansion to connect wind and CSP farms to load centers.

$$CAPEX_{R,T,transmission} = a_{CAPEX,R,transmission} P_{peak,R,T} + CAPEX_{R,T,wind\_transmission} + CAPEX_{R,T,CSP\_transmission} \tag{24}$$

$$CAPEX_{R,T,dist.\ \&\ admin} = a_{CAPEX,R,dist.\ \&\ admin} P_{peak,R,T} \tag{25}$$

We calculate $a_{CAPEX,R}$ using historical data (2000-2016) as the average dollar per peak power demand from the last five years of data (2012-2016) (see Table 8). We obtain regional peak power demand for the year 2016 from the hourly demand profile aggregated from the EIA Real Time Grid as described in the document "EIoF-EFD Hourly Demand Profiles". For simplicity, we assume peak power demand in each region for years 2017-2020 is the same as in 2016. To estimate 2000-2015 historical values for $a_{CAPEX}$, we need historical estimates of peak power generation. We use data from the EIA State Historical Tables that summarize net generation by state and type of production from EIA forms 906, 920, and 923, to aggregate annual generation by state into EIoF regions. For each region, peak power demand for year 2000 is estimated as the 2016 peak power demand multiplied by the ratio of annual generation in 2000 to annual generation in 2016: peak demand in 2000 = (peak power in 2016)×(MWh generation 2000/MWh generation 2016). Finally, peak power from 2001-2015 is assumed as a linear interpolation between the 2000 and 2016 values.

**Table 8. Transmission and Distribution + Administration cost coefficients for estimating future (2017-2050) CAPEX and OPEX.**

| **Region** | **Coefficient for Transmission CAPEX, $a_{CAPEX,transmission}$ ($2017/peak kW)** | **Coefficient for Transmission OPEX, $a_{OPEX,transmission}$ ($2017/MWh)** | **Coefficient for Distribution + Administration CAPEX, $a_{CAPEX,dist.\ \&\ admin}$ ($2017/peak kW)** | **Coefficient for Distribution + Administration OPEX, $a_{OPEX,dist.\ \&\ admin}$ ($2017/MWh)** |
|---|---|---|---|---|
| **North West (NW)** | 11.1 | 3.3 | 50.6 | 11.3 |
| **California (CA)** | 61.4 | 4.4 | 83.0 | 41.4 |
| **Mountain North (MN)** | 19.2 | 2.4 | 29.4 | 10.5 |
| **Southwest (SW)** | 26.2 | 2.0 | 56.4 | 10.3 |
| **Central (CE)** | 43.0 | 5.1 | 46.4 | 10.7 |
| **Texas (TX)** | 32.9 | 7.7 | 37.7 | 7.6 |
| **Midwest (MW)** | 29.5 | 5.8 | 70.4 | 14.2 |
| **Arkansas Louisiana (AL)** | 23.5 | 1.6 | 33.5 | 10.0 |
| **Mid-Atlantic (MA)** | 34.4 | 3.4 | 36.1 | 13.9 |
| **Southeast (SE)** | 18.3 | 1.2 | 40.2 | 13.3 |
| **Florida (FL)** | 15.6 | 1.0 | 43.7 | 11.5 |
| **New York (NY)** | 16.8 | 3.3 | 64.6 | 38.7 |
| **New England (NE)** | 69.5 | 16.7 | 64.8 | 35.1 |

The two additional cost factors in Equation (24), $CAPEX_{R,T,wind\_transmission}$ and $CAPEX_{R,T,CSP\_transmission}$, describe capital spending on new long-distance transmission to connect high quality renewable resources for wind and CSP (i.e., locations of highest regional direct normal insolation) power plants. We estimate a single capital cost of this long-distance transmission across all regions. This transmission capital cost (in \$/MW-mile) is informed by the NREL ReEDS model (NREL, 2018) that is in turn informed by the Phase II Eastern Interconnection Planning Collaborative study (EIPC, 2012).[b] From the NREL studies we estimate long-distance transmission, in each region, at a cost of 1,400 \$2010/MW-mile in 2010, and this translates to a coefficient **$a_{LDtransmission,T}$ = 1,598 \$2017/MW-mile in 2010 that we assume remains the same for each year through 2050** (e.g., the real cost of transmission is constant over time). While the NREL ReEDS model applies regional cost factors to these transmission capital costs, we do not.

Equations (26) and (27) describe the calculation of $CAPEX_{R,T,wind\_transmission}$ and $CAPEX_{R,T,CSP\_transmission}$ where the respective percentage of wind and CSP supplied from neighboring region N to the user's region R is $\%T_{toR\_fromN,wind}$ (Figure 5) and $\%T_{toR\_fromN,CSP}$ (Figure 7), the number of miles to connect wind and CSP farms to load centers is $M_{R,wind}$ (Figure 6) and $M_{R,CSP}$ (Figure 8), and the newly installed MW of capacity of wind and CSP in year $T$ is $NIC_{R,T,wind}$ and $NIC_{R,T,CSP}$. We assume the same construction schedule (or timing) for these wind and CSP long-distance transmission lines as associated with installing those power plants. If a wind or CSP power plant is in construction in year $T$, then the transmission connecting that power plant to the load centers is also in construction in year $T$.

$$CAPEX_{R,T,wind\_transmission} = a_{LDtransmission,T} NIC_{R,T,wind} \sum_{N}^{13} \%T_{toR\_fromN,wind} M_{toR\_fromN,wind} \tag{26}$$

$$CAPEX_{R,T,CSP\_transmission} = a_{LDtransmission,T} NIC_{R,T,CSP} \sum_{N}^{13} \%T_{toR\_fromN,CSP} M_{toR\_fromN,CSP} \tag{27}$$

For wind and concentrating solar power (CSP) renewable electricity technology, the EFD assumes that some of a user's desired renewable electricity consumption within one region (e.g.,

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[b] The NREL ReEDS documentation states: "Each voltage class is associated with a base capital cost sourced from the Phase II Eastern Interconnection Planning Collaborative (EIPC) report: \$2,333/MW-mile, \$1,347/MW-mile, and \$1,400/MW-mile for 345-kV, 500-kV, and 765-kV transmission lines respectively (EIPC 2012).50" with footnote 50: "The base transmission costs for ReEDS are converted to \$/MW-mile according to new transmission line cost and capacity assumptions for single circuit conductors for each voltage in EIPC (2012). The costs reported are in 2010\$ as used by the EIPC."

California) can be generated in neighboring regions (e.g., Northwest, Mountain North, and Southwest) as follows:

- Wind
    - The EFD assumes that some percentage of wind generation for consumption in the user's chosen EIoF region can come from neighboring EIoF regions. These percentages are fixed as shown in Figure 5, and the miles to connect wind from one region to another, including within the a region itself, are fixed as shown in Figure 6.

**TO**

| FROM | | NW | CA | MN | SW | CE | TX | MW | AL | MA | SE | FL | NY | NE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Northwest | California | Mountain North | Southwest | Central | Texas | Midwest | Arkansas-Louisiana | Mid-Atlantic | Southeast | Florida | New York | New England |
| NW | Northwest | 70% | 40% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| CA | California | 5% | 10% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| MN | Mountain North | 25% | 50% | 100% | 30% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| SW | Southwest | 0% | 0% | 0% | 40% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| CE | Central | 0% | 0% | 0% | 30% | 100% | 0% | 50% | 80% | 40% | 60% | 75% | 0% | 0% |
| TX | Texas | 0% | 0% | 0% | 0% | 0% | 100% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| MW | Midwest | 0% | 0% | 0% | 0% | 0% | 0% | 50% | 20% | 40% | 30% | 0% | 0% | 0% |
| AL | Arkansas-Louisiana | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| MA | Mid-Atlantic | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 20% | 10% | 0% | 30% | 0% |
| SE | Southeast | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| FL | Florida | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 25% | 0% | 0% |
| NY | New York | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 60% | 20% |
| NE | New England | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 10% | 80% |

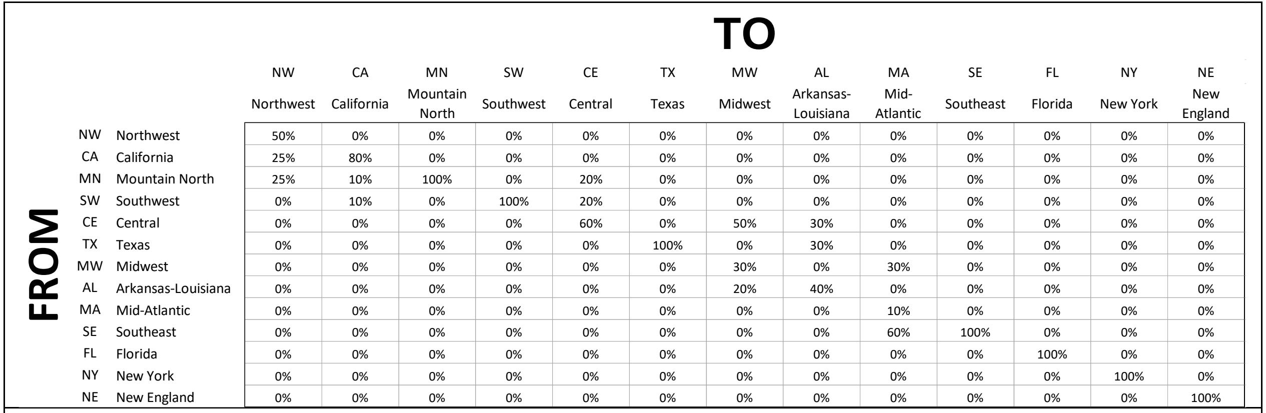
**Figure 5. The matrix indicating what percentage of wind electricity consumed in the "TO" EIoF region is assumed to be generated by power plants located in the "FROM" EIoF region. When the "TO" and "FROM" regions are the same, this means that wind electricity originates within the EIoF region itself.**

**TO**

| | | NW | CA | MN | SW | CE | TX | MW | AL | MA | SE | FL | NY | NE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Northwest | California | Mountain North | Southwest | Central | Texas | Midwest | Arkansas-Louisiana | Mid-Atlantic | Southeast | Florida | New York | New England |
| NW | Northwest | 250 | 500 | 150 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CA | California | 350 | 100 | 150 | 150 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MN | Mountain North | 250 | 800 | 200 | 250 | 450 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SW | Southwest | 0 | 400 | 200 | 100 | 350 | 85 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CE | Central | 0 | 0 | 200 | 300 | 50 | 0 | 250 | 300 | 550 | 400 | 850 | 0 | 0 |
| TX | Texas | 0 | 0 | 0 | 300 | 250 | 300 | 0 | 150 | 0 | 0 | 0 | 0 | 0 |
| MW | Midwest | 0 | 0 | 0 | 0 | 200 | 0 | 50 | 200 | 100 | 250 | 0 | 0 | 0 |
| AL | Arkansas-Louisiana | 0 | 0 | 0 | 0 | 100 | 200 | 200 | 50 | 0 | 50 | 0 | 0 | 0 |
| MA | Mid-Atlantic | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 0 | 100 | 300 | 0 | 100 | 0 |
| SE | Southeast | 0 | 0 | 0 | 0 | 0 | 0 | 200 | 400 | 200 | 50 | 350 | 0 | 0 |
| FL | Florida | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| NY | New York | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 100 | 0 | 0 | 100 | 100 |
| NE | New England | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 |

**Figure 6. The matrix indicating the number of miles of transmission assumed to connect wind electricity generated in the "FROM" EIoF region to the bulk transmission grid and load centers in the "TO" EIoF region. When the "TO" and "FROM" regions are the same, this means that bulk transmission is assumed necessary to connect wind electricity that originates and is consumed within the EIoF region itself.**

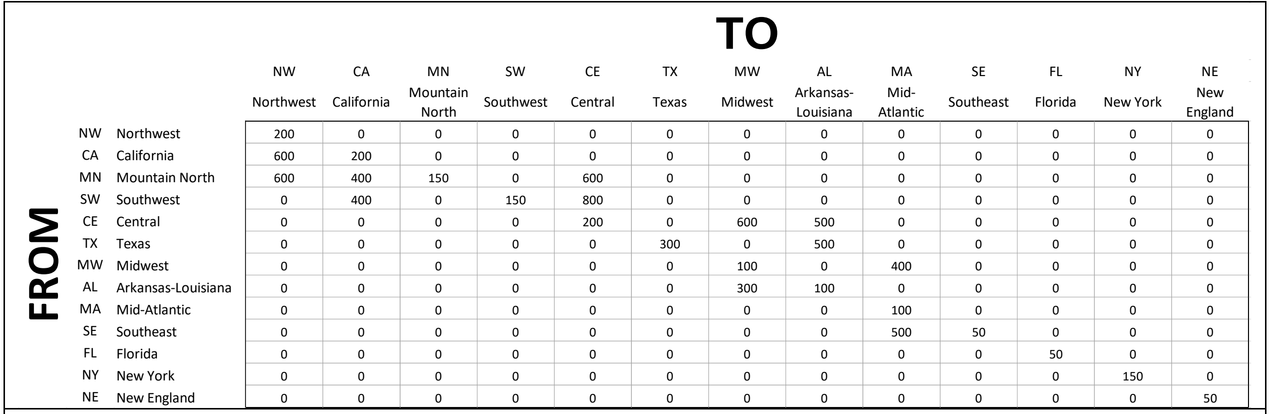
- Concentrating Solar Power (CSP)
  - The EFD assumes that some percentage of CSP generation for consumption in the user's chosen EIoF region can come from neighboring EIoF regions. These percentages are fixed as shown in Figure 7, and the miles to connect wind from one region to another, including within the a region itself, are fixed as shown in Figure 8.



TO

| | | | NW | CA | MN | SW | CE | TX | MW | AL | MA | SE | FL | NY | NE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Northwest | California | Mountain North | Southwest | Central | Texas | Midwest | Arkansas-Louisiana | Mid-Atlantic | Southeast | Florida | New York | New England |
| FROM | NW | Northwest | 50% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | CA | California | 25% | 80% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | MN | Mountain North | 25% | 10% | 100% | 0% | 20% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | SW | Southwest | 0% | 10% | 0% | 100% | 20% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| | CE | Central | 0% | 0% | 0% | 0% | 60% | 0% | 50% | 30% | 0% | 0% | 0% | 0% | 0% |
| | TX | Texas | 0% | 0% | 0% | 0% | 0% | 100% | 0% | 30% | 0% | 0% | 0% | 0% | 0% |
| | MW | Midwest | 0% | 0% | 0% | 0% | 0% | 0% | 30% | 0% | 30% | 0% | 0% | 0% | 0% |
| | AL | Arkansas-Louisiana | 0% | 0% | 0% | 0% | 0% | 0% | 20% | 40% | 0% | 0% | 0% | 0% | 0% |
| | MA | Mid-Atlantic | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 10% | 0% | 0% | 0% | 0% |
| | SE | Southeast | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 60% | 100% | 0% | 0% | 0% |
| | FL | Florida | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 100% | 0% | 0% |
| | NY | New York | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 100% | 0% |
| | NE | New England | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 100% |

**Figure 7. The matrix indicating what percentage of concentrating solar power (CSP) electricity consumed in the "TO" EIoF region is assumed to be generated by power plants located in the "FROM" EIoF region. When the "TO" and "FROM" regions are the same, this means that CSP electricity originates within the EIoF region itself.**



TO

| | | | NW | CA | MN | SW | CE | TX | MW | AL | MA | SE | FL | NY | NE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Northwest | California | Mountain North | Southwest | Central | Texas | Midwest | Arkansas-Louisiana | Mid-Atlantic | Southeast | Florida | New York | New England |
| FROM | NW | Northwest | 200 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | CA | California | 600 | 200 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | MN | Mountain North | 600 | 400 | 150 | 0 | 600 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | SW | Southwest | 0 | 400 | 0 | 150 | 800 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | CE | Central | 0 | 0 | 0 | 0 | 200 | 0 | 600 | 500 | 0 | 0 | 0 | 0 | 0 |
| | TX | Texas | 0 | 0 | 0 | 0 | 0 | 300 | 0 | 500 | 0 | 0 | 0 | 0 | 0 |
| | MW | Midwest | 0 | 0 | 0 | 0 | 0 | 0 | 100 | 0 | 400 | 0 | 0 | 0 | 0 |
| | AL | Arkansas-Louisiana | 0 | 0 | 0 | 0 | 0 | 0 | 300 | 100 | 0 | 0 | 0 | 0 | 0 |
| | MA | Mid-Atlantic | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 100 | 0 | 0 | 0 | 0 |
| | SE | Southeast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 500 | 50 | 0 | 0 | 0 |
| | FL | Florida | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 0 | 0 |
| | NY | New York | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 150 | 0 |
| | NE | New England | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 |

**Figure 8. The matrix indicating the number of miles of transmission assumed to connect concentrating solar power (CSP) electricity generated in the "FROM" EIoF region to the bulk transmission grid and load centers in the "TO" EIoF region. When the "TO" and "FROM" regions are the same, this means that bulk transmission is assumed necessary to connect CSP electricity that originates and is consumed within the EIoF region itself.**

We do not assume inter-regional electricity transfer for the following electricity fuels and generation technologies: geothermal, biomass, solar photovoltaics, nuclear, natural gas, coal, and petroleum. The EFD assumes no importation of electricity generation of these technology from one region to another. If a user desires a future with generation from these resources and technologies, then 100% of that electricity is assumed to be generated within the geographic boundary of that region.

### Transmission, Distribution, and Administration Costs – Future OPEX (2017-2050):

We estimate annual regional future operational expenditures (OPEX) for both transmission and distribution + administration in a similar manner as described for CAPEX. OPEX in each EIoF region $R$ for TD&A is a function of the total annual net electricity consumption in year $T$, $Gen_{R,T}$, estimated within that region. For region $R$ and year $T$, we use Equation (28) to calculate the annual OPEX for transmission and Equation (29) to calculate annual OPEX for distribution and administration. Each equation uses a coefficient, $a_{OPEX,R}$, with units of $2017/kWh, to multiply by the estimated annual power generation for the year. Each $a_{OPEX,R}$ value is specific to a region as shown in Table 8.

$$OPEX_{R,T,transmission} = a_{OPEX,R,transmission} Gen_{R,T} \quad (28)$$

$$OPEX_{R,T,dist.\ \&\ admin} = a_{OPEX,R,dist.\ \&\ admin} Gen_{R,T} \quad (29)$$

We calculate each $a_{OPEX,R}$ using historical data (2000-2016) as the average dollar per annual regional generation (assumed equal to electricity consumption in the region) from the last five years of data (2012-2016) (see Table 8). Historical data for the variable $Gen_{R,T}$, come from the EIA State Historical Tables that summarize net generation by state and type of production from EIA forms 906, 920, and 923, to aggregate annual generation by state into EIoF regions.

## Cash Flow and Net Tax Revenues to Government (Electricity Sector)

*(NOTE: the EFD model estimates cash flow and tax revenues for the electricity sector, but these data are not displayed to the user on the EFD web interface because these calculations necessarily require an assumed or calculated electricity sales price that is beyond the scope of the current EFD.)*

The annual cash flow ($CF_T$) for year $T$ for each technology is calculated using Equation (30) if taxable income is positive and Equation (31) if taxable income is negative. $TR$ is the tax rate, $ER_T$ is the annual energy revenue, $CR_T$ is the annual capacity revenue, $FOM_T$ is the fixed annual operation and maintenance cost, $VOM_T$ is the variable annual operation and maintenance cost, $FC_T$ is the annual fuel cost, $Dep_T$ is total depreciation of all capital in year T, $Int_T$ is total interest paid on all debt, $Eq_T$ is equity portion of total CAPEX, and $Pr_T$ is the total principal paid on all debt.

$$CF_T = (1 - TR)(ER_T + CR_T - FOM_T - VOM_T - FC_T - Dep_T - Int_T) - Eq_T + Dep_T - Pr_T \tag{30}$$

where taxable income = $(ER_T + CR_T - FOM_T - VOM_T - FC_T - Dep_T - Int_T)$

$$CF_T = ER_T + CR_T - FOM_T - VOM_T - FC_T - Int_T - Eq_T - Pr_T \qquad (31)32$$

Tax revenues to government are equal to the tax rate, $TR$, multiplied by the taxable income (if taxable income is positive).

## Cost of Energy Consumption other than for Electricity Generation

To inform users of the cost of consuming all energy, in addition to electricity, the EFD approximates spending on petroleum, natural gas, and coal across the four major end-use sectors of the economy outside of electricity generation: industrial, commercial, residential, and transportation. Because the EFD does not allow the user to select inputs that affect the majority of coal, petroleum, and natural gas use, most expenditures on these fuels are not affected by user inputs.

In this description of region-wide spending on energy, we assume the availability of estimates for energy consumption by fuel and sector for each region as described in the documentation on the "baseline" energy consumption ("Calculation of Historical and Future Baseline Energy Data by EIoF Region"). See that documentation for details on the derivation of the quantity of coal, petroleum, and natural gas energy consumed per sector and per EIoF region. These baseline data are derived from the EIA Annual Energy Outlook 2019 reference scenario.

### Petroleum Consumption and Cost (non-Electricity Generation)

Given petroleum consumption by sector in 2016 and 2050, this cost spreadsheet assumes a linear change in petroleum consumption from 2016 to 2050. Historical EIA SEDS data inform regional petroleum consumption by sector (residential, transportation, commercial, and industrial) from 2000 to 2016. Future commercial and industrial petroleum energy consumption estimates are completely unaffected by the user.

Future petroleum energy consumption estimates for transportation are affected by the user's input of the percentage of light-duty vehicles (LDVs) are driven on electricity versus liquid fuels. Because we separately estimate transportation petroleum use in 2016 for LDVs, we can separate the 2016 EIA SEDS total transportation petroleum use into two categories: LDVs and non-LDVs. We also estimate from EIA AEO 2019 reference data the petroleum energy used in 2050 for LDV travel separately from energy for all non-LDV transportation. Thus, we linearly interpolate non-LDV transportation petroleum energy consumption from 2016 to 2050. The user also selects the percentage of LDVs miles driven on petroleum in 2050. As we estimate both the regional LDV fuel efficiency (i.e., miles per gallon) and total LDV miles driven from 2016 to 2050 using EIA AEO 2019 reference case, we can then calculate a 2050 value of petroleum energy consumption in 2050 as partly determined by the user.

Future petroleum energy consumption estimates for the residential sector are affected by the user's inputs on the percentage of household heating using electricity, natural gas, and "other". Petroleum fuels are part of the "other" category that includes such petroleum fuels as propane and fuel oil as well as wood. However, given that petroleum fuels are used for non-heating energy services (such as cooking), this initial version of the EFD *does not* adjust residential petroleum consumption from 2016 to 2050 based on the user's choice of household heating. The Northeast region has the highest percentage of heating by petroleum (i.e., fuel oil) and thus we expect that region to have the highest discrepancy in residential energy spending.

With the historical data (2000-2016) and projections (2017-2050) for non-electricity sectoral petroleum consumption, we estimate energy spending on petroleum by multiplying petroleum energy consumption by the price of West Texas Intermediate (WTI) crude oil ($/BBL) assuming energy content as listed in Table A2 "Approximate Heat Content of Petroleum Production, Imports, and Exports" of the EIA Monthly Energy Review. This provides heat content of between 5.7-5.8 MMBtu/BBL from 2000-2018, and we assume future heat content (from 2019-2050) is the same as the 2019 heat content value of 5.698 MMBtu/BBL.

This method of estimating the petroleum energy spending for industrial, residential, and commercial sectors is very much an approximation, but one that allows for tracking historical variations that derive from the WTI benchmark oil price. Industrial (particularly non-refining facilities), residential, and commercial petroleum consumers do not generally purchase crude oil, but rather they purchase energy carriers as refined petroleum products that have different prices per energy content (i.e., different $/MMBtu). Further, these petroleum product prices vary across the country. Some of these prices are generally lower than the price of oil (e.g., propane), and some are higher (e.g., fuel oil). Future versions of the EFD might refine this petroleum price assumption.

## Natural Gas Consumption and Cost (non-Electricity Generation)

Given natural gas consumption by sector in 2016 and 2050, this cost spreadsheet assumes a linear change in natural gas consumption from 2016 to 2050. Historical EIA SEDS data inform regional natural gas consumption by sector (residential, transportation, commercial, and industrial) from 2000 to 2016. Future commercial, transportation, and industrial natural gas energy consumption estimates are completely unaffected by the user.

Future natural gas energy consumption estimates for the residential sector are affected by the user's inputs on the percentage of household heating using electricity, natural gas, and "other". Thus we separate residential natural gas consumption into two categories: heating and non-heating. This separation is performed using the 2016 EIA SEDS data as informed by our ResStock (single-family residential home) building simulations of amount of natural gas needed to heat 100% of residential homes in each region. As described in other documentation, we use the residential energy projections to 2050 and the ResStock simulation results to calculate 2050 estimates for heating and non-heating consumption of residential natural gas.

With the historical data (2000-2016) and projections (2017-2050) for non-electricity sectoral natural gas consumption, we estimate energy spending on natural gas by multiplying natural gas energy consumption by the Henry Hub (HH) price of natural gas ($/Mcf) assuming historical energy content (MMBtu/Mcf) as listed in Table A4 "Approximate Heat Content of Natural Gas". This provides heat content of between 1,025-1,037 Btu/Mcf from 2000-2018, and we assume future heat content (from 2019-2050) is the same as the 2019 heat content value of 1,037 Btu/Mcf.

This method of estimating the natural gas energy spending for industrial, residential, and commercial sectors is very much an approximation, but one that allows for tracking historical variations that derive from the HH benchmark natural gas price. The delivered price of natural gas varies across the country and by sector. Future versions of the EFD might refine this single natural gas price assumption by estimating delivered natural gas prices by region and sector.

## Coal Consumption and Cost (non-Electricity Generation)

Given coal consumption by sector in 2016 and 2050, this cost spreadsheet assumes a linear change in coal consumption from 2016 to 2050. Historical EIA SEDS data inform regional coal consumption by sector (residential, transportation, commercial, and industrial) from 2000 to 2016. None of the future commercial, transportation, residential, and industrial sector coal energy consumption estimates are completely affected by the user.

With the historical data (2000-2016) and projections (2017-2050) for non-electricity sectoral coal consumption, we estimate energy non-electricity spending on coal by multiplying coal energy consumption by the price of coal for "coke plants" ($/short ton) from the EIA Coal

Browser data.[c] We use historical energy content (Btu/lb) from the Coal Data Browser, which ranges from 13,131-14,352 Btu/lb from 2002 to 2018.[d] These inputs translate to coal prices ranging from 3.3 to 7.7 $2017/MMBtu. For future coal prices from 2017-2050 we use the coal price for "metallurgical industry" from the EIA AEO 2019 that generally ranges between 4.5 and 5.0 $2017/MMBtu.

This method of estimating the coal energy spending for industrial, residential, transportation, and commercial sectors is very much an approximation, but one that allows for tracking historical variations that derive from variations in coal prices experienced to the metallurgical industry that consumes the most coal after that used for electricity generation.

### Biomass Consumption (non-Electricity Generation)

The first version of the EFD does not estimate any energy spending on biomass fuels for the industrial, commercial, residential, or transportation sectors. There is an inherent assumption for the cost of liquid biofuels (e.g., ethanol) in the cost of transportation in as much as biofuels costs are somewhat incorporated into the cost of blended gasoline (i.e., E10 gasoline).

## Description of Greenhouse Gas (GHG) Emissions Calculations

This section describes the estimates for annual greenhouse gas emissions to 2050, primarily carbon dioxide from fossil fuel combustion, associated with electricity generation as well as the industrial, commercial, residential, and transportation sectors.

### GHG Emissions from Electricity Generation:

The total greenhouse gas emissions associated with a given energy generation portfolio are calculated by adding together the carbon dioxide ($CO_2$) emissions associated with the burning of fuel ($GHG_{combustion}$, in units of $CO_2$) and the one-time upstream emissions ($GHG_{upstream}$, in units of $CO_2$ equivalent, $CO_{2,eq}$). The one-time upstream emissions are derived from the manufacturing, on-site construction, raw materials extraction, materials manufacturing,

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[c] EIA Coal browser data on coal prices: https://www.eia.gov/coal/data/browser/#/topic/23?agg=0,1&geo=vvvvvvvvvvvvo&sec=vs&linechart=COAL.COST.US-98.A&columnchart=COAL.COST.US-98.A&map=COAL.COST.US-98.A&freq=A&start=2000&end=2018&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

[d] EIA Coal browser data on coal energy content: https://www.eia.gov/coal/data/browser/#/topic/22?agg=0,1&geo=vvvvvvvvvvvvo&sec=vs&freq=A&start=2000&end=2018&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0

component manufacturing, and transportation from the manufacturing facility to the construction site for the energy generation technology.

Total GHG emissions by the power plants are calculated as the sum of one-time upstream emissions associated with capacity added in that year and emissions from combustion of fuels for power generation in that year.

$$Total\ GHG\ emitted = GHG_{combustion} + GHG_{upstream} \tag{33}$$

One-time upstream emissions are calculated my multiplying the newly installed capacity added in that year ($NIC_T$) for each type of plant with the one-time upstream GHG emissions coefficient for that type of plant from Table 9.

$$GHG_{upstream,T} = GHG_{upstream,per\ kW} \cdot NIC_T \tag{34}$$

Emissions associated with combustion of coal, natural gas and petroleum products are calculated by multiplying annual generation by each type of plant, $Gen_T$, with the emissions combustion coefficient, in $CO_2$/kWh, for that type from Table 9.

$$GHG_{combustion} = GHG_{combustion,per\ kWh} \cdot Gen_T \tag{35}$$

**Table 9. Assumptions for life cycle greenhouse gas emissions associated with power generation.**

| **Fuel and Technology Type** | **One-time Upstream GHG emissions, $GHG_{upstream,\ per\ kW}$ $(\frac{g\ CO_{2,eq}}{kW})$** | **Emissions from combustion, $GHG_{combustion,per\ kWh}$ $(\frac{g\ CO_{2,eq}}{kWh})$** |
|---|---|---|
| **Coal (existing before 2020)** | 257,000 | 1,000 |
| **Coal (constructed after 2019)** | 257,000 | 700 |
| **Natural Gas CC** | 160,000 | 373 |
| **Natural Gas CT** | 6,800 | 567 |
| **Wind (Onshore)** | 619,000 | n/a |
| **Solar** | 1,630,000 | n/a |
| **CSP** | 2,970,000 | n/a |
| **Nuclear** | 350,000 | n/a |
| **Hydro** | - | n/a |
| **Geothermal** | 836,000 | n/a |
| **Biomass** | 258,000 | 0 |
| **Petroleum power plant**[*] | 160,000 | 712 |
| **Battery**[**] | n/a | 69,000 |

[*] Petroleum power plant assumed same as NGCC

[**] Battery emissions are for lithium ion batteries per kWh of energy storage *capacity*.

The values for one-time upstream emissions per fuel type come from Table C-1 in NREL's "Renewable Electricity Futures Study" and as used in the levelized cost of electricity study of Rhodes *et al.* 2016 and 2017. GHG emissions for Coal, Natural Gas, and Petroleum-fired power plants relate to both their fuel consumption and construction. We assume the other electricity technologies (Wind, Solar, CSP, Nuclear, Hydro, Geothermal, Biomass, and Battery) do not have any emissions associated with combustion, and thus their greenhouse gas emissions come solely from the one-time upstream emissions. One-time upstream emissions for lithium-ion batteries come from Hao *et al.* (2017) where they compare emissions from manufacturing Li-ion batteries of three different types: Lithium Manganese Oxide (LiMn2O4) or "LMO"; Lithium Nickel Manganese Cobalt Oxide (LiNiMnCoO2) or "NMC", and Lithium Iron Phosphate(LiFePO4) or "LMP". The manufacturing-related emissions for making these in China was estimated as 96.6, 104, and 109.3 kg $CO_{2\text{-}eq}$/kWh, respectively. For manufacturing these in the U.S, they use the BatPac Model and GREET-2015 Model of the Argonne National Laboratory to estimate emissions of U.S.-manufactured LMO, NMC, and LMP batteries as 32.9, 36.9, and 36.5 kg $CO_{2\text{-eq}}$/kWh of storage capacity. We use an average of the calculations for Chinese and American manufactured batteries.

For biomass, though it burns a carbon-based fuel for combustion, for simplicity we assume it has 0 GHG emissions from combustion since we additionally assume the fuel source derives from carbon resources that are equally sequestered from the atmosphere, implying net zero GHG emissions. More detailed analysis of the biomass life cycle is beyond the scope of the EFD.

## Total GHG Emissions from Fossil Fuel Consumption (not associated with Electric Sector Power Generation per Fuel Type):

The total greenhouse gas emissions associated with the given portfolio of energy generation infrastructure includes the emissions associated with fossil fuel consumption outside of that associated with electricity generation. Therefore we aggregate emissions for each fossil fuel (coal, natural gas, petroleum) across the industrial, residential, commercial, and transportation sectors to get total emissions.

The historical data for fossil fuel come from the EIA state level data of $CO_2$ emissions per fuel and sector (https://www.eia.gov/environment/emissions/state/). Using historical data, we derive specific emissions factors ($tCO_2$/MMBtu) for each region and sector for the year 2016. Table 10 shows the data and coefficients for coal, and Table 11 shows the emissions factors for petroleum. We assume the emissions factors remain the same from 2016 to 2050. The coefficient for natural gas in all sectors in all regions is assumed as 0.053 $tCO_2$/MMBtu.

**Table 10. Assumptions for non-electricity *coal* consumption $CO_2$ emissions factors for each sector and each EIoF region. The same emissions factor is used for all sectors as non-electricity coal consumption is dominated by the industrial sector.**

| Region | Coal energy consumption in 2016 (quads) | Emissions from combustion in 2016 ($MtCO_2$) | Emissions Factor ($tCO_2$/MMBtu) |
|---|---|---|---|
| **North West (NW)** | 0.002 | 0.18 | 0.0946 |
| **California (CA)** | 0.032 | 3.04 | 0.0947 |
| **Mountain North (MN)** | 0.066 | 6.20 | 0.0946 |
| **Southwest (SW)** | 0.006 | 0.56 | 0.0946 |
| **Central (CE)** | 0.132 | 12.50 | 0.0947 |
| **Texas (TX)** | 0.014 | 1.31 | 0.0947 |
| **Midwest (MW)** | 0.397 | 37.30 | 0.0939 |
| **Arkansas Louisiana (AL)** | 0.009 | 0.84 | 0.0947 |
| **Mid-Atlantic (MA)** | 0.387 | 36.13 | 0.0934 |
| **Southeast (SE)** | 0.152 | 14.30 | 0.0942 |
| **Florida (FL)** | 0.013 | 1.24 | 0.0947 |
| **New York (NY)** | 0.014 | 1.32 | 0.0942 |
| **New England (NE)** | 0.001 | 0.05 | 0.0942 |

**Table 11. Assumptions for non-electricity *petroleum* consumption $CO_2$ emissions factors for each sector and each EIoF region. Sectors are: I=industrial, C=commercial, R=residential, T= transportation.**

| Region | Petroleum energy consumption in 2016 (quads) | | | | Emissions from combustion in 2016 ($MtCO_2$) | | | | Emissions Factor ($tCO_2/MMBtu$) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | I | C | R | T | I | C | R | T | I | C | R | T |
| **North West (NW)** | 0.168 | 0.029 | 0.015 | 0.981 | 7.5 | 2.0 | 1.0 | 68.3 | 0.045 | 0.070 | 0.066 | 0.070 |
| **California (CA)** | 0.433 | 0.083 | 0.024 | 3.062 | 19.3 | 5.9 | 1.5 | 210.5 | 0.044 | 0.071 | 0.062 | 0.069 |
| **Mountain North (MN)** | 0.255 | 0.040 | 0.028 | 1.232 | 11.6 | 2.8 | 1.8 | 84.4 | 0.045 | 0.070 | 0.062 | 0.068 |
| **Southwest (SW)** | 0.101 | 0.021 | 0.009 | 0.671 | 4.2 | 1.5 | 0.5 | 45.7 | 0.041 | 0.070 | 0.062 | 0.068 |
| **Central (CE)** | 0.304 | 0.030 | 0.029 | 1.080 | 16.3 | 2.1 | 1.8 | 74.6 | 0.054 | 0.070 | 0.062 | 0.069 |
| **Texas (TX)** | 3.203 | 0.052 | 0.020 | 3.170 | 124.6 | 3.6 | 1.2 | 219.6 | 0.039 | 0.071 | 0.062 | 0.069 |
| **Midwest (MW)** | 0.865 | 0.113 | 0.150 | 4.063 | 36.5 | 7.9 | 9.4 | 277.2 | 0.042 | 0.070 | 0.063 | 0.068 |
| **Arkansas Louisiana (AL)** | 1.262 | 0.015 | 0.005 | 0.906 | 68.0 | 1.1 | 0.3 | 62.8 | 0.054 | 0.071 | 0.062 | 0.069 |
| **Mid-Atlantic (MA)** | 0.806 | 0.157 | 0.193 | 4.386 | 31.3 | 11.1 | 13.4 | 299.7 | 0.039 | 0.070 | 0.069 | 0.068 |
| **Southeast (SE)** | 0.440 | 0.100 | 0.053 | 3.510 | 18.3 | 7.0 | 3.4 | 239.9 | 0.042 | 0.070 | 0.064 | 0.068 |
| **Florida (FL)** | 0.102 | 0.056 | 0.006 | 1.497 | 4.0 | 3.9 | 0.4 | 102.5 | 0.040 | 0.070 | 0.062 | 0.068 |
| **New York (NY)** | 0.092 | 0.072 | 0.114 | 1.071 | 1.9 | 5.2 | 8.1 | 73.5 | 0.021 | 0.072 | 0.071 | 0.069 |
| **New England (NE)** | 0.080 | 0.076 | 0.223 | 1.017 | 1.9 | 5.3 | 15.9 | 68.8 | 0.024 | 0.070 | 0.071 | 0.068 |

## Aggregation of Cost Calculations

The "Aggregation" tab of the Google Sheet collects and organizes all cost calculations as well as the annual electricity generation and capacity per technology. The costs displayed on the EFD are in real 2017 U.S. dollars.

For electricity infrastructure, the CAPEX and OPEX calculations for the user's chosen region from each of the individual technologies to be displayed on the EIoF interactive webpage. The total annual CAPEX and OPEX in each year (*T*) for the entire electricity system is calculated by summing the annual CAPEX and OPEX expenses for each of the following energy technologies categories that are separately displayed on the EFD website:

- Power Plants and Storage is a sum of:
  - Coal, Natural Gas Combined Cycle, Natural Gas Combustion Turbine, Petroleum (Combined Cycle), Nuclear, Wind, Solar PV, CSP, Geothermal, Biomass, and Storage (assuming lithium-ion battery costs)
- Electricity Transmission, Distribution, and (utility) Administration is a sum of
  - Transmission
  - Distribution + Administration

The EFD does not separately calculate CAPEX and OPEX for non-electricity infrastructure, such as oil and gas infrastructure within the upstream (e.g., drilling rigs), midstream (e.g., pipelines) and downstream (e.g., oil refineries) segments of the business. Instead, as discussed in an earlier section, the EFD calculates spending on primary energy resources of coal, natural gas, and petroleum that are consumed by the non-electric sectors of commercial, industrial, transportation, and residential. These costs are plotted together with the CAPEX and OPEX costs for the electricity system.

In addition to displaying the cost data in total dollars per year, the EFD also displays the costs on a per capita and per regional GDP basis. These calculations provide perspective to the user, in comparison with historical data, on whether their selected 2050 scenario might cost more or less to each person or regional economy. Each regional economy is assumed to grow at the same rate as the national economy.

The reasons for expressing energy system spending relative to regional GDP is that we have observed instances when, at the national scale, spending on energy as a fraction of GDP has become so high as to trigger, or at least be correlated with, recession (in 1970s and 2008) (King, 2015; Bashmakov, 2007; Bashmakov and Myshak, 2018). Because energy consumption (and its efficiency of conversion to useful work) is highly correlated with GDP, high energy costs are a negative feedback that slow the rate of energy consumption, and thus also useful work and GDP

(Ayes and Warr, 2005; Ayres and Warr, 2009, Warr *et al.*, 2010). Thus, this calculation of energy costs relative to GDP provides perspective to the user, in comparison with historical data, on whether their selected 2050 scenario might be consistent with economic growth.

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