Long Term Rate Forecasting Tool

Purpose: This long-term rate forecasting tool was developed by Concentric Energy Advisors to assist the Colorado Public Utilities Commission better understand the rate impacts of various utility decisions involving investment levels, depreciation approaches, capital costs, new technologies, and changes in retail sales, among others.

Caveats: This is a simple spreadsheet model of the long-term costs and rates of an electric utility. It will not be as accurate as a utility's finance, accounting, and resource planning personnel and systems. For different input assumptions the model will produce rate changes that are directionally correct and of the proper magnitude. However, this model should not be used to derive definitive conclusions regarding total costs and rate impacts. To the extent that this model and a utility have disparate cost and rate impact estimates associated with a specific scenario it should be assumed that the utility estimate is the more accurate.

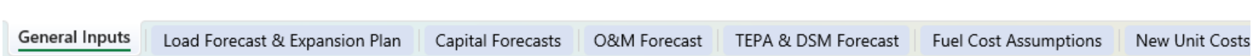
Inputs: The model is intended to be a generic framework that could be applied to any vertically integrated electric utility. However, the baseline inputs used reflect the costs and resource plan for Public Service Company of Colorado. The input data was taken from public documents filed recently with the Colorado Commission, FERC, and investor presentations. Long term load forecasts, resource retirements, and additions were taken from the Company's 2021 Electric Resource Plan. Trends in O&M and other costs were derived from Appendix A filings and applied to future years. The cost of individual plant costs and purchase power prices were taken from recent FERC Form 1 filings. The model also uses load and renewable energy patterns from EIA's Grid Monitor tool. Finally the near term capital investments are reflective of recent investor presentations.

Dispatch Module: A second spreadsheet model was developed to produce a simplified generation dispatch simulation. The model starts with a Colorado specific load shape from the EIA Grid Monitor tool. Next the load shapes is adjusted to fit the annual energy and peak demand specified by the user. Next wind and solar generation are simulated based on shapes also from EIA Grid Monitor, the model tracks renewable generation in excess of load minus a minimum dispatchable generation amount and record excess renewable generation as curtailment . For storage dispatch the model uses perfect foresight to identify the optimal hours to charge and discharge. The default assumptions of 80% round trip efficiency and charging and discharging that is spread over 8 hours each, but these assumptions can be modified by the user. The simulation is completed by dispatching hydro, coal, intermediate gas, and peaking gas.

Because the dispatch module is so large most users will prefer to keep the dispatch module spreadsheet closed and only open and update as necessary. Updating the dispatch module is accomplished by having both spreadsheets open and pressing F9 to update all formulas.

MODEL STRUCTURE

The model is separated into seven color coded sections. The first light blue section contains inputs that can be modified by the user.



BTM Solar | Community Solar | Owned Units | Purchased Power

The orange tabs provide summary and detailed model outputs.

30yr Rate Forecast | Historical and Forecasted Rates | Dispatch Output | Saved Scenario | Scenario Comparison

The light green tabs are used to aggregate results related to revenue requirements and other costs.

Plant In-Service | Accumulated Depreciation | ADIT | Taxes | Return | Depreciation | Taxes Other Than Income | PTCs | Securitization

Dark green tabs contain revenue requirement calculation for several functional categories of capital investments,

Book Lives | Rev Req - Intangible | Rev Req - Production | Rev Req - Transmission | Rev Req - Substations | Rev Req - Primary&Secondary
Rev Req - Transformers&Services | Rev Req - Meters | Rev Req - Lighting | Rev Req - General | Rev Req - WldFr&ResInc&Other | Rev Req Template

The purple tabs include the cost and performance information related to new production resources that are added through a user defined expansion plan.

Generic Owned Gas Intemediate | Generic Owned Gas Peaking | Generic Owned Wind | Generic Owned Solar | Generic Owned Storage
Generic Purchased Gas Intermedi | Generic Purchased Gas Peaking | Generic Purchased Wind | Generic Purchased Solar | Generic Purchased Storage

The other light green tabs are used for calculating the revenue requirements associated with new generic resources that are added though the user defined expansion plan.

Rev Req Securitization | Rev Req Coal | Rev Req Gas | Rev Req Wind | Rev Req Solar | Rev Req Battery | Rev Req Hydro

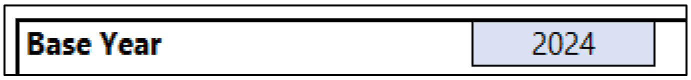
The peach colored tabs at the end of the model provide documentation of some inputs that were used in the model or in some way informed the model.

2021 IRP Unit Capacity & Retire | 2022 FF1 Owned Unit Data | 2022 FF1 Owned Unit Data p2 | FF1 Purch Power Summary | 2022 FF1 Purch Power
2021 FF1 Purch Power | 2020 FF1 Purch Power | Load Forecasts | DG Solar | Losses | BTM Solar Capacity Factor | Fuel Forecasts

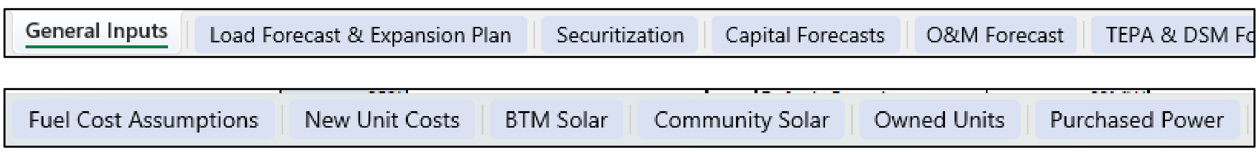
User Guide

INPUTS

User defined inputs are identified with light blue shading.



The light blue tabs indicate the sheets that contain inputs that the user may wish to modify.



The “**General Inputs**” tab contains several inputs that a user may be interested in modifying. This tab also includes graphical illustration of the resulting rate forecasts so that the user can quickly see how changes to the input assumptions impact the model’s forecasts.

The “General Inputs” tab includes several escalation factors, currently set at 2.5%. For O&M and purchased energy the escalations are applied to 2025 and beyond. But the user can go to those specific tabs in the model and enter custom forecasts of costs if they choose to do so. For the capital categories the escalation factors are applied in 2029 and beyond. The last escalation factor for Baseline Inflation Rate is only used to take current average rates and grow them at a simple rate for comparison purposes. The default input of 2.5% is close to the average inflation rate of 2.3% from 2012 to 2023 but was set slightly higher to reflect recent inflation rates that have been above average.

Taxes Other Than Income (TOTI) are primarily property taxes paid by the utility. The Taxes Other Than Income input factor is applied to the total utility net plant to derive the annual TOTI expense. The 1.7% default input is equal to PSCo’s average from 2016 through 2022, which ranged from 1.4% to 1.8%

The Average Availability factor is used by the dispatch simulation to modify the expected generation for each category. The input reflects the fact that not all units are available all the time. But more practically the input can be used to fine tune the dispatch model to more closely match either historical or forecasted dispatch information provided by the utility. For example, if the simple dispatch model results in coal generation that is higher than what the utility is forecasting, the average availability input can be lowered, which in turn will decrease the amount of coal generation forecasted by the dispatch model.

This tab also includes an input for the current rate and escalation assumption for production tax credits (“PTCs”). As the utility builds more owned renewable generation PTC will become a larger and larger part of the overall revenue requirements. The current value is set to the more recently announced value of $27.50/MWh. The PTC rate escalates over time to account for inflation. The latest inflation adjustment factor was published in June 2023, and that equals 1.8909. The inflation factor is published annually by the IRS, and in some cases, corrections are even made throughout the year.

This tab also has inputs for modeling securitization of a given amount of capital. The user specifies the total amount to be securitized and the year in which it is to begin. Next the user specifies the book life and tax life for the asset had it not been securitized. This is typically a shorter period of time and is used by the model to establish a baseline revenue requirement for the investment before securitization. The rest of the inputs specify the term of the securitization, the interest rate applied to the asset, the upfront cost (issuance fee), and the ongoing cost to service the financial instrument.

The Demand Response inputs in the “General Assumptions” tab allow the user to quickly modify the forecasted level of demand response capacity in the model. The user can also enter a more detailed set of demand response inputs in the “Load Forecast & Expansion Plan” tab. The simplified modeling in the “General Inputs” tab specifies the cost, growth rate, and maximum level of demand response capacity. The default inputs are based on the final update to the 2021 Resource plan and specify a growth rate of 38MW per year and a maximum capacity of 767MW. The maximum capacity input is limiting because the 2024 level of demand response is 538MW, so there relatively little incremental capacity available. The default average cost of demand response of $4.05/kW-month is based on the Company’s most recent DSM plan. For scenarios simulating higher levels of demand response the user should carefully consider the incremental cost of those resources as they will likely be more expensive than current programs. The demand response capacity is used by the “Load Forecast & Expansion Plan” to calculate the required new capacity in future years.

The “General Inputs” tab also includes a “Save Current Scenario” button that when clicked will run a simple macro that saves the output results of the current input assumptions so that they can be compared to an alternate scenario.

“General Inputs” Tab

Base Year	2024	
O&M Escalation	2.5%	
Purchased Power Escalation	2.5%	
Generation Capital Escalation	2.5%	
Transmission Capital Escalation	2.5%	
Distribution Capital Escalation	2.5%	
Wildfire ,Resiliency, Other	2.5%	
Baseline Inflation Rate	2.5%	- Used for simple baseline rate

Cost of Capital	Weight	Rate	WACC
Debt	41.78%	4.40%	1.84%
Equity	58.22%	9.20%	5.36%
Weighted			7.19%

Tax Rates	
State Income Tax Rate	4.55%
Federal Income Tax Rate	21.00%
Combined Tax Rate	24.59%

Taxes Other Than Income	1.70%	Applied to Net Plant

Depreciation	Current Average	Modified Average
Production	40 years	40 years
Transmission	50 years	50 years
Distribution	50 years	50 years

Average Availability	
Coal	75%
Gas Intermediate	75%
Gas Peaking	100%
Hydro	50%
Wind	95%
Solar	95%
Storage	95%

First Year PTC	$27.50/MWh
Escalation	2.5%

Annual Energy Escalator	
Default Growth Rate	1.9%
Modified Growth Rate	1.9%

Peak Demand Escalator	
Default Growth Rate	1.0%
Modified Growth Rate	1.0%

Gas Price Escalator	
Default Growth Rate	2.2%
Modified Growth Rate	2.2%

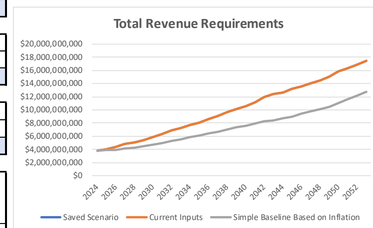
Post 2028 Generic Capital
Annual Capital (Excluding Production) Based on 2020-2022 Plant Additions
$615,310,000
2024-2028 Annual Average Capital Spend (Excluding Production) Based on March 2024 Investor Presentation
$2,835,000,000
2029 Capital (Excluding Production)
$2,800,000,000

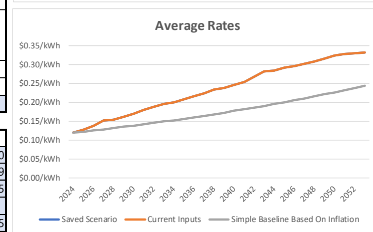
Securitization	
Total Amount	$0
Start Year	2029
Book Life	35
Tax Life	15 years
Securitization Term	35
Securitization Rate	3%
Issuance Fees Fixed	$10,000,000
Issuance Fees Rate	0.74%
Ongoing Securitization F	$1,000,000

Behind The Meter Solar	
Default Growth	93MW
Default Growth Rate	6%
Modified Growth	93MW
Modified Growth Rate	6%

Demand Response	
Default Max DR	767MW
Default Growth Rate	38MW
Average Cost	$4.05/kW-month
Modified Max DR	767MW
Modified Growth Rate	38MW
Modified Ave Cost	$4.05/kW-month
DR Cost Escalation	2.50%

Save Current Scenario





The “**General Inputs**” tab provides charts showing the forecasted revenue requirement and average rates. For comparison purposes the charts include a Simple Baseline Based on Inflation. This trend uses the 2024 forecast as the starting point for and escalates those values based on 2.5% or an alternative value that the user can modify in the escalation inputs in this tab.

The “**Load Forecast & Expansion Plan**” tab includes long-term forecasts of annual sales and peak demand. The tab also includes a section where the user can specify the Company’s production expansion plan. The annual sales and peak demand inputs are based on the 2021 ERP Appendix D - Updated Modeling Assumptions, filed Nov 29, 2022, in Proceeding 21A-0141E. The model does not have the capability of optimizing a least cost expansion plan so the user must specify the size and timing of wind, solar, storage, and natural gas additions to the system. The model has been populated with the expansion plan approved in the most recent ERP proceeding and then based on the average capacity additions in that plan the baseline inputs specify annual additions of 400MW wind, 400MW solar, and 500MW of storage. The model also tracks capacity surpluses and short falls. To the extent that the firm capacity of resources is below the specified reserve margin target the model is set up to add natural gas peaking units to cover the short fall.

The "**Load Forecast & Expansion Plan**" tab also includes an input for transmission and distribution line losses. This input is necessary to translate the sales input to total energy requirements at the generation level, which is used by the dispatch model to simulate annual generation. The default input value of 5.44% is based on the input assumptions documented in the 2021 Resource Plan (Attachment AKJ-2 Technical Appendix, page 64).

"Load Forecast & Expansion Plan" Tab – Load Inputs

	Energy Forecast (21A-0141E -2021 Appendix D - Updated Modeling Assumptions Nov 29 2022)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
	Net Sales	31,518,784 MWh	31,932,299 MWh	31,526,094 MWh	32,102,617 MWh	32,815,516 MWh	33,471,814 MWh	34,356,553 MWh
	BTM Solar	-1,252,645 MWh	-1,427,701 MWh	-1,578,667 MWh	-1,713,573 MWh	-1,859,722 MWh	-2,013,900 MWh	-2,152,018 MWh
	Gross Sales	32,771,429 MWh	33,360,000 MWh	33,104,762 MWh	33,816,190 MWh	34,675,238 MWh	35,485,714 MWh	36,508,571 MWh
5%	Losses	+1,638,571 MWh	+1,668,000 MWh	+1,655,238 MWh	+1,690,810 MWh	+1,733,762 MWh	+1,774,286 MWh	+1,825,429 MWh
	Annual Energy (@ Transmisson)	34,410,000 MWh	35,028,000 MWh	34,760,000 MWh	35,507,000 MWh	36,409,000 MWh	37,260,000 MWh	38,334,000 MWh

	Peak Demand & Reserve Margin (21A-0141E -2021 Appendix D - Updated Modeling Assumptions Nov 29 2022)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
	Peak Demand (@ Transmission)	7,195 MW	7,259 MW	6,990 MW	7,066 MW	7,165 MW	7,279 MW	7,402 MW
	Demand Response	-538 MW	-576 MW	-614 MW	-653 MW	-691 MW	-729 MW	-767 MW
	Net Peak Load Obligation	6,657 MW	6,683 MW	6,376 MW	6,414 MW	6,474 MW	6,550 MW	6,635 MW
	Reserve Margin	19.20%	19.20%	19.10%	18.00%	18.00%	18.00%	18.00%
	Wholesale Backup Reserves	48 MW	48 MW	11 MW	11 MW	11 MW	11 MW	11 MW
	Total Capacity Requirement	7,983 MW	8,014 MW	7,604 MW	7,579 MW	7,651 MW	7,740 MW	7,840 MW

"Load Forecast & Expansion Plan" Tab – Expansion Plan Inputs

1	**Expansion Plan**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
2	Owned Gas Intermediate								
3	Purchase Gas Intermediate								
4	Owned Gas Peaking		442 MW			0 MW	241 MW	162 MW	30 MW
5	Purchase Gas Peaking		239 MW			0 MW	241 MW	162 MW	30 MW
6	Owned Wind	474 MW	338 MW	452 MW	0 MW	**200 MW**	200 MW	200 MW	200 MW
7	Purchased Wind	249 MW	0 MW	0 MW	187 MW	**200 MW**	200 MW	200 MW	200 MW
8	Owned Solar	473 MW	439 MW	0 MW	0 MW	**200 MW**	200 MW	200 MW	200 MW
9	Purchased Solar	341 MW	366 MW	0 MW	0 MW	**200 MW**	200 MW	200 MW	200 MW
10	Owned Storage	632 MW	158 MW	0 MW	0 MW	**250 MW**	250 MW	250 MW	250 MW
11	Purchased Storage	0 MW	1,058 MW	0 MW	0 MW	**250 MW**	250 MW	250 MW	250 MW

The "**Capital Forecast**" tab allows the user to input specific capital forecasts for intangible, transmission, distribution, general & common, and wildfire/resiliency/other capital. The capital input for each year represents capital put in-service. The capital inputs are used by the model to calculate rate based, book depreciation, and tax depreciation data that is used in the total revenue requirement calculations.

Capital investments associated with generation assets are addressed through the expansion plan inputs. When the user specifies new additions of owned generating facilities the model automatically adds the associated capital to the revenue requirement calculations. The assumed cost of new generation resources can be modified in the **"New Unit Cost"** tab. The capital inputs for transmission, distribution, and other capital categories were based on a March 2024 investors presentation. The investor presentation lists a total of $17 billion for total investments in the electric system ($19.2 billion PSCo total less $2.2 billion for natural gas). The model is populated with $11.3 billion investments in transmission, distribution, and other capital categories. The input expansion plan results in $5.3 billion for electric generation capital investments. The total of $16.6 billion in the model is slightly less than the $17billion in the investor presentation due to differences in the assumed cost of new generation assets.

“Capital Forecasts” Tab

Capital Forecast / New Plant In-Service							
	2024	2025	2026	2027	2028	2029	2030
Intangible	$300,000	$300,000	$300,000	$300,000	$300,000	$307,500	$315,188
Production (On-Going at Existing Plants Only)		2%	Percent of Gross Plant		Other production capital investments are driven by expansio		
Production (Expansion Plan	$0	$0	$2,340,006,960	$2,031,343,862	$897,208,406	$0	$1,071,921,587
Transmission	$820,000,000	$1,110,000,000	$1,260,000,000	$1,320,000,000	$930,000,000	$200,000,000	$205,000,000
Distribution							
Substations	$111,820,449	$133,890,274	$158,902,743	$147,132,170	$160,374,065	$51,496,259	$52,783,666
Primary & Secondary	$549,625,935	$658,104,738	$781,047,382	$723,192,020	$788,279,302	$253,117,207	$259,445,137
Services & Transformers	$41,695,761	$49,925,187	$59,251,870	$54,862,843	$59,800,499	$19,201,995	$19,682,045
Meters	$34,114,713	$40,847,880	$48,478,803	$44,887,781	$48,927,681	$15,710,723	$16,103,491
Lighting	$22,743,142	$27,231,920	$32,319,202	$29,925,187	$32,618,454	$10,473,815	$10,735,661
Distribution Total	$760,000,000	$910,000,000	$1,080,000,000	$1,000,000,000	$1,090,000,000	$350,000,000	$358,750,000
General & Common	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$100,000,000	$102,500,000
Wildfire/Resiliency/Other	$109,700,000	$119,700,000	$119,700,000	$119,700,000	$89,700,000	$2,149,692,500	$2,203,434,813
Total Capital / New Plant In-	$1,790,000,000	$2,240,000,000	$4,900,006,960	$4,571,343,862	$3,107,208,406	$2,800,000,000	$3,941,921,587

March 2024 Investor Presentation

PSCo Base Capital Expenditures by Function

$ Millions

	2024	2025	2026	2027	2028	Total
Electric Transmission	$820	$1,110	$1,260	$1,320	$930	$5,440
Electric Distribution	$760	$910	$1,080	$1,000	$1,090	$4,840
Natural Gas	$460	$450	$450	$450	$410	$2,220
Other	$220	$210	$220	$220	$190	$1,060
Electric Generation	$190	$330	$390	$400	$100	$1,410
Renewables	$850	$2,220	$920	$230	$10	$4,230
Total	**$3,300**	**$5,230**	**$4,320**	**$3,620**	**$2,730**	**$19,200**

The “O&M Forecast” tab allows the user to specify the O&M budgets for several functional categories, except for the O&M budget or production which is addressed through the expansion plan assumptions. The default inputs for 2024 are based on historic actuals as reported in the annual Appendix A filings and a simple escalator is applied in future years. However, the use could input specific values in each year should they choose.

“O&M Forecast” Tab

O&M Forecast							
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Production	$249,640,055	$259,827,828	$274,151,490	$305,704,028	$312,656,860	$309,690,752	$333,040,579
Transmission	$70,000,000	$71,750,000	$73,543,750	$75,382,344	$77,266,902	$79,198,575	$81,178,539
Distribution							
Substations	$20,000,000	$20,500,000	$21,012,500	$21,537,813	$22,076,258	$22,628,164	$23,193,868
Primary & Secondary	$100,000,000	$102,500,000	$105,062,500	$107,689,063	$110,381,289	$113,140,821	$115,969,342
Services & Transformers	$8,000,000	$8,200,000	$8,405,000	$8,615,125	$8,830,503	$9,051,266	$9,277,547
Meters	$6,000,000	$6,150,000	$6,303,750	$6,461,344	$6,622,877	$6,788,449	$6,958,161
Lighting	$4,000,000	$4,100,000	$4,202,500	$4,307,563	$4,415,252	$4,525,633	$4,638,774
Distribution Total	$138,000,000	$141,450,000	$144,986,250	$148,610,906	$152,326,179	$156,134,333	$160,037,692
Regional Markets	$500,000	$512,500	$525,313	$538,445	$551,906	$565,704	$579,847
Customer Accounts	$70,000,000	$71,750,000	$73,543,750	$75,382,344	$77,266,902	$79,198,575	$81,178,539
DSM	$120,052,838	$122,694,062	$125,949,525	$129,204,988	$132,460,451	$135,715,914	$138,971,377
Sales	$10,000,000	$10,250,000	$10,506,250	$10,768,906	$11,038,129	$11,314,082	$11,596,934
A&G	$175,000,000	$179,375,000	$183,859,375	$188,455,859	$193,167,256	$197,996,437	$202,946,348
Total	$833,192,894	$857,609,390	$887,065,702	$934,047,821	$956,734,586	$969,814,373	$1,009,529,856

The “TEPA & DSM Forecast” tab contains simple inputs based on the 2024 DSM plan budgets and the recent commission deliberation regarding the Company ‘s Transportation Electrification Plan. The default inputs include a simple escalation for DSM budgets after 2026 and a fixed budget of $56 million annually for the TEPA.

“TEPA & DSM Forecast” Tab

Transportation Electrification Plan Adjustment							
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
O&M & Rebates	$10,000,000	$56,666,667	$56,666,667	$56,666,667	$56,666,667	$56,666,667	$56,666,667
Demand Side Management Cost Adjustment							
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Energy Efficiency Programs	$83,579,944	$84,178,279	$85,284,472	$86,390,665	$87,496,858	$88,603,051	$89,709,244
Energy Efficiency Indirect Program	$7,695,700	$7,887,743	$8,303,629	$8,719,515	$9,135,401	$9,551,287	$9,967,173
Demand Response Program	$26,132,478	$27,986,362	$29,840,246	$32,486,484	$35,246,383	$38,123,972	$41,123,413
Demand Response Indirect Program	$2,084,716	$2,081,678	$1,961,178	$1,840,678	$1,720,178	$1,599,678	$1,479,178
Demand Management Approved in Other Proceedings	$560,000	$560,000	$560,000	$560,000	$560,000	$560,000	$560,000
Total	$120,052,838	$122,694,062	$125,949,525	$129,204,988	$132,460,451	$135,715,914	$138,971,377

The “Fuel Cost Assumptions” tab contain the forecasted cost of natural gas and coal commodities. The forecasted costs are based on the 2021 ERP Appendix D - Updated Modeling Assumptions, filed Nov 29 2022, in Proceeding 21A-0141E. The user can update the tab with new fuel cost assumptions or can modify the growth rate for natural gas costs in the “General Inputs” tab.

“Fuel Cost Assumptions” Tab

Fuel Costs $/mmBtu							
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Coal	$1.51	$1.55	$1.59	$1.62	$1.66	$1.70	$1.77
Natural Gas	$4.69	$3.90	$4.13	$4.28	$4.38	$4.29	$4.28

The “New Unit Costs” tab contains the cost assumptions for new gas plants, wind, solar, and battery storage resources. The cost assumptions are based in the 2022 U.S. Energy Information Administration’s Cost and Performance Characteristics of New Generating Technologies documentation. The 2022 overnight costs are escalated to 2024 using a 5% inflation rate assumption. The tab also contains the input assumption for the cost of firm gas deliveries at natural gas plants based on 2021 ERP Appendix D - Updated Modeling Assumptions, filed Nov 29, 2022, in Proceeding 21A-0141E.

“New Unit Costs” Tab

Firm Gas	$11.98/kW-yr								
		5%	5%						
Gas Intermediate	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital ($/kW)	$1,176	$1,235	$1,297	$1,329	$1,362	$1,396	$1,431	$1,467	$1,504
O&M ($/kW)	$14	$14	$27	$28	$28	$29	$30	$31	$31
Gas Peaker	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital ($/kW)	$867	$910	$956	$980	$1,004	$1,029	$1,055	$1,081	$1,109
O&M ($/kW)	$8	$8	$21	$21	$22	$22	$23	$23	$24
Wind	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital ($/kW)	$2,098	$2,203	$1,800	$1,845	$1,891	$1,938	$1,987	$2,037	$2,087
O&M ($/kW)	$30	$31	$33	$33	$34	$35	$36	$37	$38
Solar	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital ($/kW)	$1,448	$1,520	$1,596	$1,636	$1,677	$1,719	$1,762	$1,806	$1,851
O&M ($/kW)	$17	$18	$19	$19	$20	$20	$21	$21	$22
Storage	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capital ($/kW)	$1,270	$1,334	$980	$1,005	$1,030	$1,055	$1,082	$1,109	$1,137
O&M ($/kW)	$46	$48	$50	$52	$53	$54	$56	$57	$59

The “BTM Solar” tab contains the forecasted capacity growth for net metered solar which is based on the 2021 ERP Updated Modeling Inputs and Assumptions, filed Nov 2022, pages 21-25 , Proceeding No. 21A-0141E. The tab also includes the assumption for the average capacity factor for net metered solar which was based on a PVWatts simulation. The information entered here is used by the model to calculate the impact of additional BMT solar in the dispatch simulation. Additional BMT solar will reduce the fossil fuel generation and create fuel cost savings. The BMT solar energy also reduces sales volumes, which can put upward pressure on rates.

“BTM Solar” Tab

	Behind The Meter Solar							
		2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
	Gross Installed Capacity	779 MW	888 MW	982 MW	1,066 MW	1,157 MW	1,252 MW	1,338 MW
	ELCC	19.9%	19.5%	19.1%	18.8%	18.4%	18.1%	17.7%
C.F% Relative to	Firm Capacity	155 MW	172 MW	185 MW	197 MW	208 MW	221 MW	231 MW
Max AC Output								
18.4%	Annual Energy @ Customer	1,252,645 MWh	1,427,701 MWh	1,578,667 MWh	1,713,573 MWh	1,859,722 MWh	2,013,900 MWh	2,152,018 MWh

The "Community Solar" tab contains the forecasted capacity growth for solar gardens which is based on the 2021 ERP Updated Modeling Inputs and Assumptions, filed Nov 2022, pages 21-25 , Proceeding No. 21A-0141E. The tab also includes the capacity factor assumption as well as the annual energy credit which based on the Company's current tariff.

"Community Solar" Tab

	Community Solar							
		2024	2025	2026	2027	2028	2029	2030
	Gross Installed Capacity	237 MW	324 MW	361 MW	458 MW	638 MW	639 MW	695 MW
	ELCC	36.7%	34.6%	33.8%	32.3%	30.3%	30.2%	29.6%
Capacity	Firm Capacity	87 MW	112 MW	122 MW	148 MW	193 MW	193 MW	206 MW
Factor								
22.0%	Annual Energy	457,320 MWh	625,197 MWh	696,593 MWh	883,766 MWh	1,231,097 MWh	1,233,027 MWh	1,341,086 MWh
2.50%	Ave CSG Credit	$80.67/MWh	$82.68/MWh	$84.75/MWh	$86.87/MWh	$89.04/MWh	$91.27/MWh	$93.55/MWh
2.50%	REC Payment to Developer	$5.00/MWh	$5.13/MWh	$5.25/MWh	$5.38/MWh	$5.52/MWh	$5.66/MWh	$5.80/MWh

The "Owned Units" tab contains the operational information for company owned generating units including retirement year, plant costs, capacity, heat rate, variable O&M, and fixed O&M expenses. The capacity, heat rate, and retirement year information was from the 2021 ERP Volume 2 Technical Appendix Page 123, Proceeding No. 21A-0141E. The cost information for owned generating units was derived from FERC Form 1 data. Based on the cost and the age of the units the "Owned Units" tab calculates a high-level estimate of each unit's annual revenue requirement.

"Owned Units" Tab

Owned Units	Name	Type	2024	2025	2026	2027	2028	2029	2030
In-Service Year	Alamosa	Gas Peaking	1977						
Retirement Year	Alamosa	Gas Peaking	2026						
Total Plant Cost	Alamosa	Gas Peaking	$11,258,140						
Gross Capacity (MW)	Alamosa	Gas Peaking	35	35	35				
ELCC (%)	Alamosa	Gas Peaking	77%	77%	77%				
Firm Capacity (MW)	Alamosa	Gas Peaking	27	27	27				
Availability (%)	Alamosa	Gas Peaking	100%	100%	100%				
Heat Rate (mmBtu/MWh)	Alamosa	Gas Peaking	15.50	15.50	15.50				
Variable O&M (/MWh)	Alamosa	Gas Peaking	$2.52	$2.58	$2.64				
Fixed O&M	Alamosa	Gas Peaking	$264,902	$271,525	$278,313				
Plant In-Service	Alamosa	Gas Peaking	$11,258,140	$11,483,302	$11,712,968				
Accumulated Deprecation	Alamosa	Gas Peaking	-$7,019,105	-$8,432,117	-$9,957,710				
Accumulated Deferred Taxes	Alamosa	Gas Peaking	$0	$0	$0				
Rate Base	Alamosa	Gas Peaking	$4,239,034	$3,051,186	$1,755,259				
Return	Alamosa	Gas Peaking	$304,980	$219,519	$126,283				
Depreciation Expense	Alamosa	Gas Peaking	$1,413,011	$1,525,593	$1,755,259				
Taxes	Alamosa	Gas Peaking	$74,056	$53,304	$30,665				

The "Purchased Power" tab contains the operational information for purchased capacity and purchased energy contracts. The capacity and contract expiration date are from the 2021 ERP Volume 2 Technical Appendix Page 123, Proceeding No. 21A-0141E. Estimates for the pricing of the purchase power contracts were derived from historical data in FERC Form 1.

“Purchased Power” Tab

Purchased Power									
	Name	**Type**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Retirement Year	Bronco Plains	Wind	2045						
Gross Capacity (MW)	Bronco Plains	Wind	301	301	301	301	301	301	301
ELCC (%)	Bronco Plains	Wind	13%	0	0	0	0	0	0
Firm Capacity (MW)	Bronco Plains	Wind	40	40	40	40	40	40	40
Availability (%)	Bronco Plains	Wind	95%	95%	95%	95%	95%	95%	95%
Heat Rate (mmBtu/kWh)	Bronco Plains	Wind	-	-	-	-	-	-	-
Variable O&M (/MWh)	Bronco Plains	Wind	$13.10	$13.43	$13.77	$14.11	$14.46	$14.83	$15.20
Capacity Rate ($/kW-month)	Bronco Plains	Wind	$0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Retirement Year	Brush	Gas Peaking	2025						
Gross Capacity (MW)	Brush	Gas Peaking	313	313					
ELCC (%)	Brush	Gas Peaking	100%	1					
Firm Capacity (MW)	Brush	Gas Peaking	313	313					
Availability (%)	Brush	Gas Peaking	100%	100%					
Heat Rate (mmBtu/kWh)	Brush	Gas Peaking	10.00	10.0					
Variable O&M (/MWh)	Brush	Gas Peaking	$10.00	$10.25					
Capacity Rate ($/kW-month)	Brush	Gas Peaking	$5.64	$5.78					

CAPITAL REVENUE REQUIREMENTS METHODOLOGY

Capital investment and the associated revenue requirements are modeled for ten different categories: Intangible, Production, Transmission, Substations, Primary & Secondary Distribution, Services & Transformers, Meters, Lighting, General & Common, and Wildfire/Resiliency/Other. These categories are split between existing capital and new capital investments. The existing capital is based on 2022 Appendix A filings and escalated annually by 3% to 2024. Using the plant in-service, annual depreciation expense, and accumulated depreciation the model calculates the implied average book life and average age for each capital category, which are fundamental inputs used in the forecasting of future revenue requirement .

“Book Lives” Tab

2022 Apendix A	Plant In-Service	Accum Depr	ADIT	Depreciation Expense	Implied Book Life	Implied Average Age
Intangible	$666,843	($10,846)	($522,856)	$106,250	6.4 yrs	0.1 yrs
Production	$7,109,576,979	($2,214,817,316)	($981,874,165)	$309,785,225	23.5 yrs	7.1 yrs
Transmssion	$3,112,198,237	($615,381,101)	($520,607,437)	$63,152,942	50.5 yrs	9.7 yrs
Distribution	$6,362,358,237	($1,648,782,999)	($922,406,490)	$148,150,701	44.0 yrs	11.1 yrs
General & Commc	$699,089,379	($275,806,891)	($72,772,009)	$46,226,914	15.5 yrs	6.0 yrs
Other	$767,544,190	($372,665,225)	($69,392,548)	$62,833,301	12.5 yrs	5.9 yrs
Distriubution Detail						
Substations	$934,717,477	($207,221,880)	($158,017,972)	$18,035,577	53.1 yrs	11.5 yrs
Primary & Secon	$4,595,620,696	($1,084,921,896)	($674,087,931)	$102,130,263	46.1 yrs	10.6 yrs
Services & Trans	$347,685,623	($195,665,406)	($38,122,280)	$8,401,059	42.4 yrs	23.3 yrs
Meters	$286,786,589	($103,318,506)	($19,956,363)	$11,458,284	25.7 yrs	9.0 yrs
Lighting	$197,547,852	($57,655,311)	($32,221,946)	$8,125,517	24.9 yrs	7.1 yrs
Total	$6,362,358,237	($1,648,782,999)	($922,406,492)	$148,150,700	44.0 yrs	11.1 yrs

This data feeds into the ten dark green revenue requirements tabs.

Rev Req - Intangible | Rev Req - Production | Rev Req - Transmission | Rev Req - Substations | Rev Req - Primary&Secondary | Rev Req - Transformers&Ser

Rev Req - Meters | Rev Req - Lighting | Rev Req - General | Rev Req - WldFr&ResInc&Other | Rev Req Template

These tabs perform standard revenue requirements calculations. The tabs calculate annual depreciation based on the average book life for each category and calculates the tax depreciation and deferred taxes based on the Modified Accelerated Cost Recovery Systems (“MACRS”) schedule. The revenue requirements tabs then track net plant and rate base in order to calculate the annual return and income taxes. Because the Appendix A existing plant in-service is somewhat dated the model uses the output from the middle of the revenue requirements tab. For example, the implied average age of transmission assets was 9.7 years. In the **“Rev Req – Transmission”** Tab the model begins using data in year 10 for existing transmission as indicated by the green highlighting in the tab.

“Rev Req – Transmission” Tab

Rate Base & Revenue Requirements											
Transmission											
Rate Base	**1 year**	**2 year**	**3 year**	**4 year**	**5 year**	**6 year**	**7 year**	**8 year**	**9 year**	**10 year**	**11 year**
Plant In-Service	$3,190,003,193	$3,190,003,193	$3,190,003,193	$3,190,003,193	$3,190,003,193	$3,190,003,193	$3,190,003,193	$3,190,003,193	$3,190,003,193	$3,190,003,193	$3,190,003,193
Accumulated Deprecation	($15,788,236)	($63,152,942)	($126,305,884)	($189,458,826)	($252,611,768)	($315,764,710)	($378,917,652)	($442,070,594)	($505,223,536)	($568,376,478)	($631,529,420)
Net Book Value	$3,174,214,957	$3,126,850,251	$3,063,697,309	$3,000,544,367	$2,937,391,425	$2,874,238,483	$2,811,085,541	$2,747,932,599	$2,684,779,657	$2,621,626,715	$2,558,473,773
Accumulated Deferred Taxes	($35,345,229)	($133,535,263)	($245,102,697)	($331,250,215)	($397,077,489)	($446,625,034)	($485,698,631)	($521,555,510)	($557,451,617)	($593,347,725)	($616,376,961)
Total Rate Base	$3,138,869,728	$2,993,314,988	$2,818,594,612	$2,669,294,152	$2,540,313,935	$2,427,613,449	$2,325,386,910	$2,226,377,089	$2,127,328,040	$2,028,278,990	$1,942,096,812
Revenue Requirements	**1 year**	**2 year**	**3 year**	**4 year**	**5 year**	**6 year**	**7 year**	**8 year**	**9 year**	**10 year**	**11 year**
Equity Return	$168,125,396	$160,329,135	$150,970,692	$142,973,801	$136,065,311	$130,028,803	$124,553,304	$119,250,100	$113,944,795	$108,639,491	$104,023,366
Debt Return	$57,702,470	$55,026,708	$51,814,788	$49,070,168	$46,699,099	$44,627,304	$42,748,053	$40,927,935	$39,107,097	$37,286,258	$35,701,954
Deprecation Expense	$31,576,471	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942
Income Tax Expense	$54,836,319	$52,293,465	$49,241,086	$46,632,794	$44,379,499	$42,410,612	$40,624,706	$38,894,996	$37,164,600	$35,434,205	$33,928,595
O&M Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue Requirements	$312,240,656	$330,802,250	$315,179,508	$301,829,705	$290,296,851	$280,219,660	$271,079,004	$262,225,973	$253,369,435	$244,512,896	$236,806,858
Calculation Details											
Book Deprecation	**1 year**	**2 year**	**3 year**	**4 year**	**5 year**	**6 year**	**7 year**	**8 year**	**9 year**	**10 year**	**11 year**
Beginning Balance	$0	$31,576,471	$94,729,413	$157,882,355	$221,035,297	$284,188,239	$347,341,181	$410,494,123	$473,647,065	$536,800,007	$599,952,949
Deprecation Expense	$31,576,471	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942	$63,152,942
Ending Balance	$31,576,471	$94,729,413	$157,882,355	$221,035,297	$284,188,239	$347,341,181	$410,494,123	$473,647,065	$536,800,007	$599,952,949	$663,105,891
Average	$15,788,236	$63,152,942	$126,305,884	$189,458,826	$252,611,768	$315,764,710	$378,917,652	$442,070,594	$505,223,536	$568,376,478	$631,529,420
Tax Depreciation	**1 year**	**2 year**	**3 year**	**4 year**	**5 year**	**6 year**	**7 year**	**8 year**	**9 year**	**10 year**	**11 year**
Tax Depreciation Rate	10.0%	18.0%	14.4%	11.5%	9.2%	7.4%	6.6%	6.6%	6.6%	6.6%	3.3%
Beginning Balance	0	$319,000,319	$893,200,894	$1,352,561,354	$1,720,049,722	$2,014,168,016	$2,249,271,251	$2,458,216,460	$2,667,161,670	$2,876,425,879	$3,085,371,088
Tax Depreciation	$319,000,319	$574,200,575	$459,360,460	$367,488,368	$294,118,294	$235,103,235	$208,945,209	$208,945,209	$209,264,209	$208,945,209	$104,632,105
Ending Balance	$319,000,319	$893,200,894	$1,352,561,354	$1,720,049,722	$2,014,168,016	$2,249,271,251	$2,458,216,460	$2,667,161,670	$2,876,425,879	$3,085,371,088	$3,190,003,193
Average	$159,500,160	$606,100,607	$1,122,881,124	$1,536,305,538	$1,867,108,869	$2,131,719,634	$2,353,743,856	$2,562,689,065	$2,771,793,774	$2,980,898,484	$3,137,687,141

This data then flows into the light green calculation tabs.

Plant In-Service | Accumulated Depreciation | ADIT | Taxes | Return | Deprecation | Taxes Other Than Income

The format of each of these tabs is the same. At the top of each tab the relevant data for existing capital is brought in from the appropriate revenue requirements tab. The following is an example from the “Accumulated Depreciation” tab and shows how the accumulated depreciation from the “Rev Req – Transmission” tab is brought into the model’s total.

"Accumulated Depreciation" Tab

Accumulated Deprecation - Existing Capital					
	2024	2025	2026	2027	2028
Intangible	($26,563)	($106,250)	($212,500)	($318,750)	($425,000)
Production	($2,974,787,606)	($3,422,111,491)	($2,803,899,114)	($3,078,299,187)	($3,171,918,556)
Transmission	($568,376,478)	($631,529,420)	($694,682,362)	($757,835,304)	($820,988,246)
Distribution					
Substations	($198,391,347)	($216,426,924)	($234,462,501)	($252,498,078)	($270,533,655)
Primary & Secondary	($1,021,302,630)	($1,123,432,893)	($1,225,563,156)	($1,327,693,419)	($1,429,823,682)
Services & Transformers	($193,224,357)	($201,625,416)	($210,026,475)	($218,427,534)	($226,828,593)
Meters	($103,124,556)	($114,582,840)	($126,041,124)	($137,499,408)	($148,957,692)
Lighting	($56,878,619)	($65,004,136)	($73,129,653)	($81,255,170)	($89,380,687)
Distribution Total	($1,572,921,509)	($1,721,072,209)	($1,869,222,909)	($2,017,373,609)	($2,165,524,309)
General & Common	($277,361,484)	($323,588,398)	($369,815,312)	($416,042,226)	($462,269,140)
Wildfire/Resiliancy/Other	($134,868,479)	($157,346,559)	($179,824,639)	($202,302,719)	($224,780,799)
Total Plant In-Service	($5,528,342,118)	($6,255,754,327)	($5,917,656,836)	($6,472,171,795)	($6,845,906,049)

The model also uses the dark green revenue requirement tabs for new capital. For a given set of inputs including book life, tax life, return, cost of debt, capital structure, and tax rates the revenue requirements will be the same in terms of percentages for any size capital investment. At the bottom of the green revenue requirements tabs the model tracks depreciation, taxes, return, etc. in terms of percentages.

"Rev Req – Transmission" Tab (bottom)

Cost of Capital	Weight	Rate	WACC					
Debt	41.78%	4.40%	1.84%					
Equity	58.22%	9.20%	5.36%					
Weighted			7.19%					
Tax Rates								
State Income Tax Rate	4.55%							
Federal Income Tax Rate	21.00%							
Combined Tax Rate	24.59%							
Capital Investment	$3,190,003,193							
Deprecation								
Book Depreciation	51 years							
Tax Deprecation	10 years							
Tax Deprecation Schedules	10%	18%	14%	12%	9%	7%	7%	7%
1 3 years	33.3%	44.5%	14.8%	7.4%	0.0%	0.0%	0.0%	0.0%
2 5 years	20.0%	32.0%	19.2%	11.5%	11.5%	5.8%	0.0%	0.0%
3 7 years	14.3%	24.5%	17.5%	12.5%	8.9%	8.9%	8.9%	4.5%
4 10 years	10.0%	18.0%	14.4%	11.5%	9.2%	7.4%	6.6%	6.6%
5 15 years	5.0%	9.5%	8.6%	7.7%	6.9%	6.2%	5.9%	5.9%
6 20 years	3.8%	7.2%	6.7%	6.2%	5.7%	5.3%	4.9%	4.5%
Depreciation Expense	1.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Accumulated Depr	-0.5%	-2.0%	-4.0%	-5.9%	-7.9%	-9.9%	-11.9%	-13.9%
ADIT	-1.1%	-4.2%	-7.7%	-10.4%	-12.4%	-14.0%	-15.2%	-16.3%
Taxes	1.7%	1.6%	1.5%	1.5%	1.4%	1.3%	1.3%	1.2%
Revenue Requirements	9.8%	10.4%	9.9%	9.5%	9.1%	8.8%	8.5%	8.2%
Plant In-Service	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Return	7.1%	6.8%	6.4%	6.0%	5.7%	5.5%	5.2%	5.0%

The light green calculation tabs take these percentages and applies them to the capital input data to calculate the revenue requirement data for new capital additions to the system. The following example shows how the transmission accumulated depreciation percentage profile is used to calculate the accumulated depreciation balance for the 2025 transmission capital investments.

"Accumulated Depreciation" Tab

Accumulated Deprecation Profiles							
	1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year
Intangible	-4%	-16%	-31%	-47%	-62%	-78%	-93%
Production	-1%	-4%	-9%	-13%	-17%	-21%	-26%
Transmission	-0.5%	-2%	-4%	-6%	-8%	-10%	-12%
Distribution							
Substations	0%	-2%	-4%	-6%	-8%	-9%	-11%
Primary & Secondary	-1%	-2%	-4%	-7%	-9%	-11%	-13%
Services & Transformers	-1%	-2%	-5%	-7%	-9%	-12%	-14%
Meters	-1%	-4%	-8%	-12%	-16%	-19%	-23%
Lighting	-1%	-4%	-8%	-12%	-16%	-20%	-24%
Distribution Total							
General & Common	-2%	-6%	-13%	-19%	-26%	-32%	-39%
Wildfire/Resiliancy/Other	-1%	-3%	-6%	-9%	-11%	-14%	-17%
2025							
	Capital	2025	2026	2027	2028	2029	2030
Intangible	$300,000	-$11,659	-$46,634	-$93,268	-$139,902	-$186,536	-$233,170
Production							
Transmission	$1,110,000,000	-$5,493,707	-$21,974,826	-$43,949,652	-$65,924,478	-$87,899,305	-$109,874,131
Distribution							
Substations	$133,890,274	-$630,108	-$2,520,431	-$5,040,862	-$7,561,294	-$10,081,725	-$12,602,156
Primary & Secondary	$658,104,738	-$3,567,151	-$14,268,602	-$28,537,204	-$42,805,806	-$57,074,408	-$71,343,010
Services & Transformers	$49,925,187	-$294,227	-$1,176,910	-$2,353,819	-$3,530,729	-$4,707,639	-$5,884,548
Meters	$40,847,880	-$398,058	-$1,592,232	-$3,184,464	-$4,776,697	-$6,368,929	-$7,961,161
Lighting	$27,231,920	-$273,195	-$1,092,781	-$2,185,562	-$3,278,343	-$4,371,124	-$5,463,904

Finally, the sum of the various capital categories for existing and new capital is brought into the "30yr Rate Forecast" tab to calculate the overall revenue requirements for the system.

"30yr Rate Forecast" Tab

Total Revenue Requirements	2024	2025	2026	2027	2028	2029
Rate Base						
Plant In-Service	$19,379,041,264	$21,782,314,023	$25,725,267,867	$30,409,068,671	$33,418,505,407	$35,762,659,997
Accumulated Depreciation	($5,528,342,118)	($6,268,890,223)	($6,018,491,177)	($6,806,838,280)	($7,556,708,224)	($8,063,438,999)
ADIT	($2,458,455,094)	($2,592,252,729)	($2,700,308,971)	($3,007,337,408)	($3,426,236,493)	($3,804,654,239)
CWIP	$700,000,000	$700,000,000	$700,000,000	$700,000,000	$700,000,000	$700,000,000
Other Rate Base	($70,000,000)	($70,000,000)	($70,000,000)	($70,000,000)	($70,000,000)	($70,000,000)
Rate Base	$12,022,244,052	$13,551,171,072	$17,636,467,720	$21,224,892,983	$23,065,560,689	$24,524,566,759
Return	$864,947,562	$974,947,133	$1,268,866,252	$1,527,037,661	$1,659,465,603	$1,764,434,670
O&M	$843,192,894	$914,274,909	$943,730,695	$990,712,250	$1,013,399,331	$1,026,477,240
Depreciation Expense	$727,385,646	$790,189,048	$737,895,164	$934,840,076	$1,049,248,269	$1,083,183,353
Taxes	$434,485,350	$489,462,153	$630,149,796	$756,528,755	$825,623,852	$882,349,016
Fuel	$341,942,011	$317,390,673	$292,366,465	$254,995,166	$279,781,951	$297,757,436
Purchased Power	$715,823,920	$777,556,962	$791,154,192	$859,769,887	$761,412,152	$804,355,370
PTCs	($165,823,766)	($169,969,360)	($301,943,609)	($414,418,221)	($500,056,190)	($410,036,081)
Impact of Securitization	$0	$0	$0	$0	$0	$0
Total	$3,761,953,616	$4,093,851,519	$4,362,218,956	$4,909,465,574	$5,088,874,968	$5,448,521,006

OUTPUTS

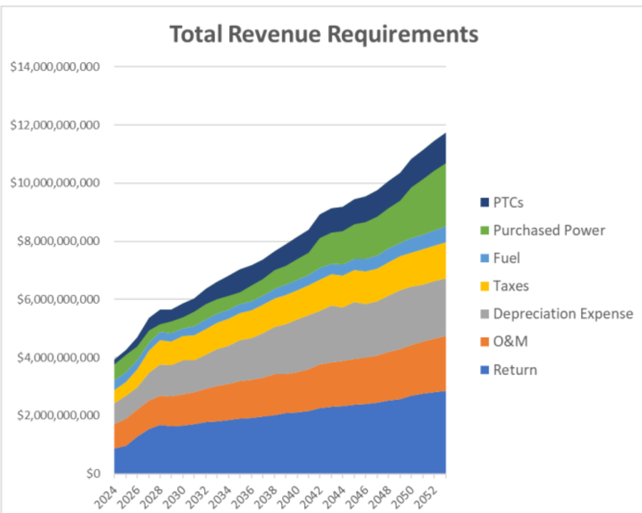
The light orange tabs contain the model outputs. The "30yr Rate Forecast" tab contains extensive output data based on the current input assumptions. The model will also save the output of a

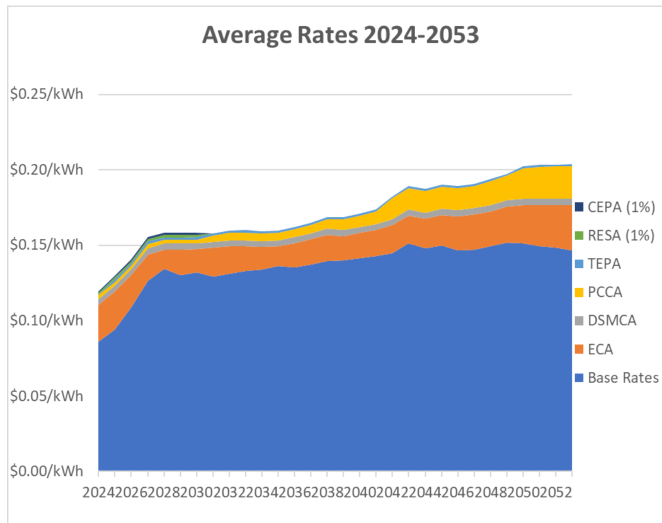
30yr Rate Forecast	Dispatch Output	Saved Scenario	Scenario Comparison

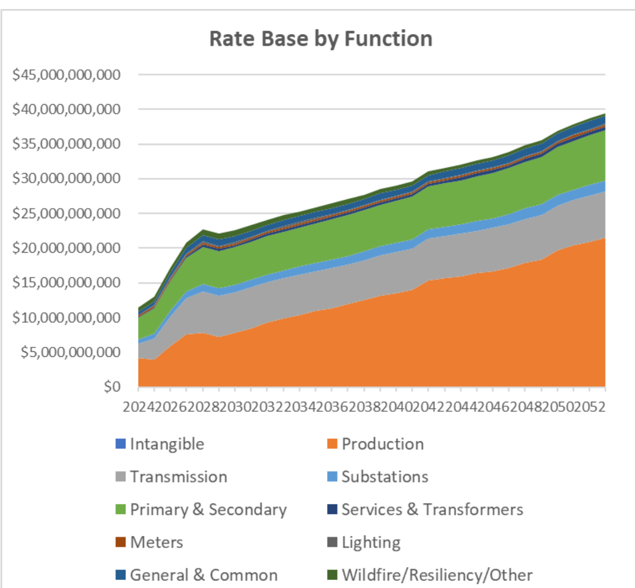
The “30yr Rate Forecast” tab ab the “30yr Rate Forecast” tab contains extensive output data on the scenario being evaluated including:

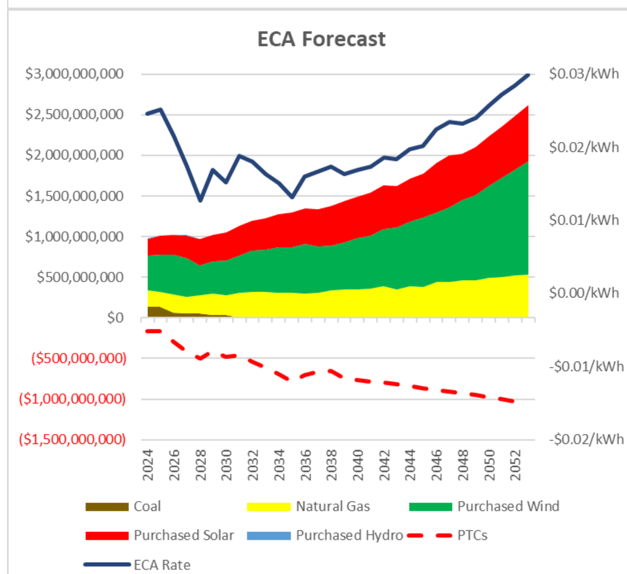
- Total Revenue Requirements – Rate base, return on rate base, O&M, depreciation, taxes, fuel, purchased power, and PTCs
- Average Rates – Base rates, ECA, DSMCA, PCCA, TEPA
- Electric Commodity Adjustment Detail – Coal, natural gas, purchased wind, purchased solar, purchased hydro, PTCs, RESA transfers.
- Energy Mix
- Rate Base by Function – Intangible, production, transmission, distribution

“30yr Rate Forecast” Tab



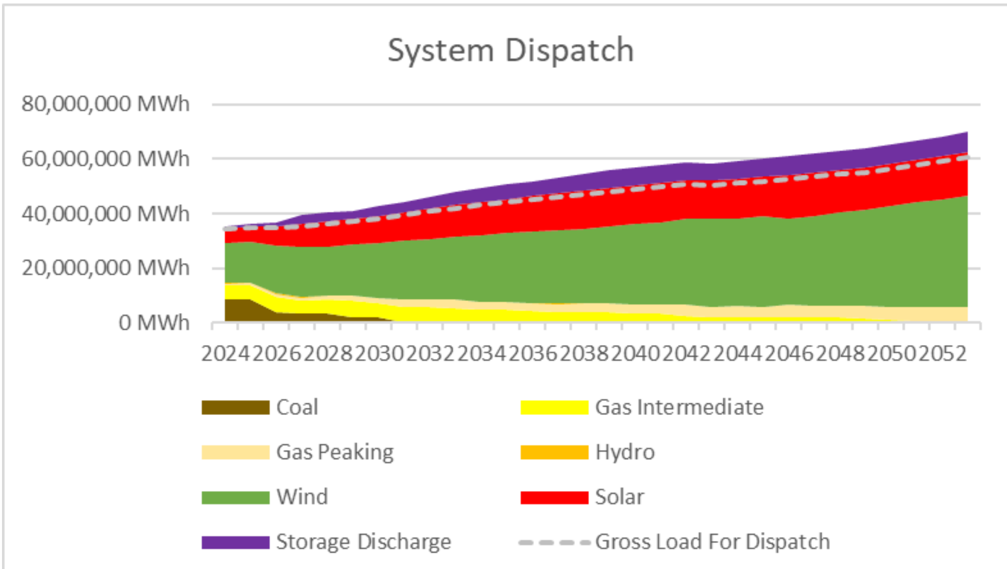


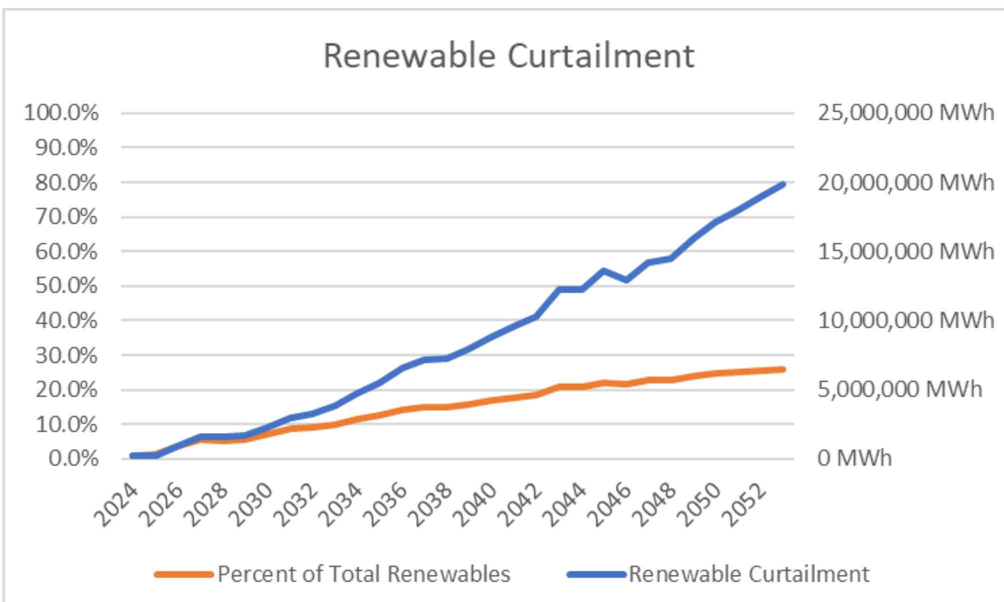


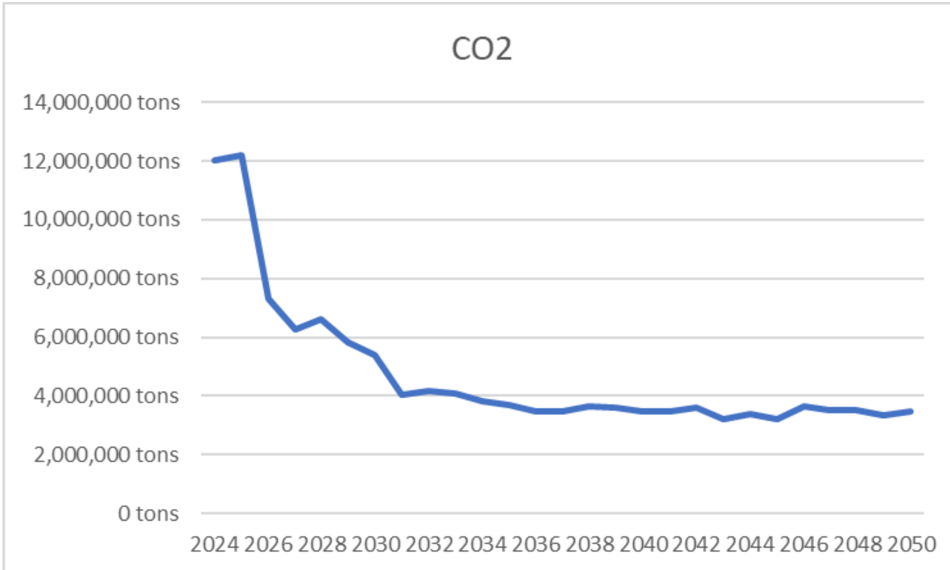


The “Dispatch Output” tab contains the results of the Dispatch Module spreadsheet. The sheet contains information on energy mix, fuel cost, purchased energy, renewable energy curtailment, and CO2 emissions.

“Dispatch Output” Tab







The remaining two output tabs, “Saved Scenario” and “Scenario Comparison” can be used to compare and contrast two sets of model results. When a scenario is saved using the macro in the “General Inputs” tab the results are saved in the “Saved Scenario” tab. The “Scenario Comparison” tab is set to show the difference between the saved scenario and a scenario with modified input assumptions.

SCENARIO COMPARISON

EXAMPLE 1 – Future Capital Investment:

1) As a baseline scenario the 2029 capital investment level is set to $650 million, reflecting the approximate level of capital investment in the 2020-2022 timeframe.

“General Inputs” tab

Post 2028 Generic Capital
Annual Capital (Excluding Production) Based on 2020-2022 Plant Additions
$615,310,000
2024-2028 Annual Average Capital Spend (Excluding Production) Based on March 2024 Investor Presentation
$2,835,000,000
2029 Capital (Excluding Production)
$650,000,000

This input is intended to allow the user to quickly update the long-range capital spend assumption to evaluate the impact on rates. The 2029 capital spend assumption is escalated annually using an inflation assumption also found in the “General Inputs” tab.

The user also has the option of constructing a more detailed capital forecast in the “Capital Forecast” tab

2) Save the output of the baseline scenario by clicking the Save Current Scenario box in the “General Inputs” tab. This will run a simple macro that saves the output data in the “Saved Scenario” tab for comparison to alternate scenarios.

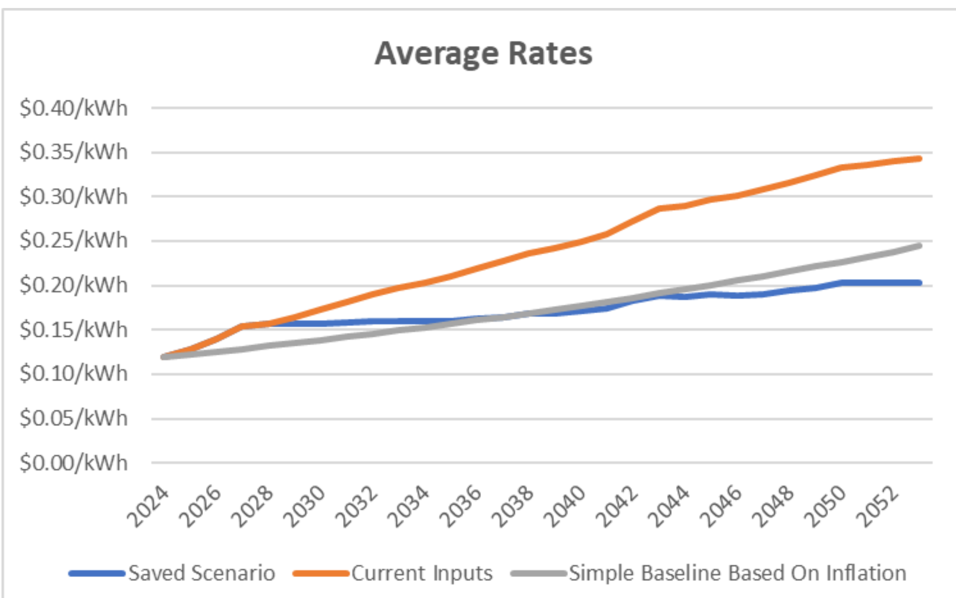
Save Current Scenario

3) Next update the long-range capital investment assumption from $650 million per year to $2.8 billion.

Post 2028 Generic Capital Annual Capital (Excluding Production) Based on 2020-2022 Plant Additions
$615,310,000
2024-2028 Annual Average Capital Spend (Excluding Production) Based on March 2024 Investor Presentation
$2,835,000,000
2029 Capital (Excluding Production)
$2,800,000,000

4) The model will then compare the result of the modified assumptions to the saved scenario. Not unexpectedly, the impact of a much higher capital spend assumption is a substantial increase in overall average rates.

"General Inputs" Tab



The "Scenario Comparison" tab provides additional detail regarding the difference between the two scenarios. It shows that by 2035 the higher level of capital spending will results in an incremental rate base of $14 billion and revenue requirements that are $1.95 billion higher than the baseline.

“Scenario Comparison” Tab

Total Revenue Requirements	2028	2029	2030	2031	2032	2033	2034	2035
Rate Base								
Plant In-Service	$0	$2,150,000,000	$4,353,750,000	$6,612,593,750	$8,927,908,594	$11,301,106,309	$13,733,633,966	$16,226,974,815
Accumulated Deprecation	$0	($15,357,143)	($77,169,643)	($201,956,027)	($391,290,642)	($646,787,193)	($970,099,730)	($1,362,923,652)
ADIT	$0	($9,442,531)	($46,126,765)	($116,342,608)	($216,169,314)	($342,064,022)	($490,791,888)	($660,200,513)
CWIP	$0	$0	$0	$0	$0	$0	$0	$0
Other Rate Base	$0	$0	$0	$0	$0	$0	$0	$0
Rate Base	$0	$2,125,200,326	$4,230,453,592	$6,294,295,115	$8,320,448,638	$10,312,255,093	$12,272,742,348	$14,203,850,650
Return	$0	$152,898,813	$304,362,522	$452,846,839	$598,619,670	$741,921,380	$882,969,812	$1,021,904,557
O&M	$0	$0	$0	$0	$0	$0	$0	$0
Depreciation Expense	$0	$30,714,286	$92,910,714	$156,662,054	$222,007,176	$288,985,927	$357,639,147	$428,008,697
Taxes	$0	$73,416,358	$146,608,247	$218,942,708	$290,481,445	$361,279,391	$431,385,926	$500,831,339
Fuel	$0	$0	$0	$0	$0	$0	$0	$0
Purchased Power	$0	$0	$0	$0	$0	$0	$0	$0
PTCs	$0	$0	$0	$0	$0	$0	$0	$0
Impact of Securitization	$0	$0	$0	$0	$0	$0	$0	$0
Total	$0	$257,029,456	$543,881,483	$828,451,600	$1,111,108,291	$1,392,186,699	$1,671,994,885	$1,950,744,593
Sales	0 MWh	0 MWh	0 MWh	0 MWh	0 MWh	0 MWh	0 MWh	0 MWh
Average Rate	$0.0000/kWh	$0.0077/kWh	$0.0158/kWh	$0.0235/kWh	$0.0304/kWh	$0.0371/kWh	$0.0436/kWh	$0.0498/kWh

EXAMPLE 2 – Additional Behind the Meter Solar

1. Starting with the high capital spend scenario in the previous example the user saves this scenario as the baseline for comparison.

Save Current Scenario

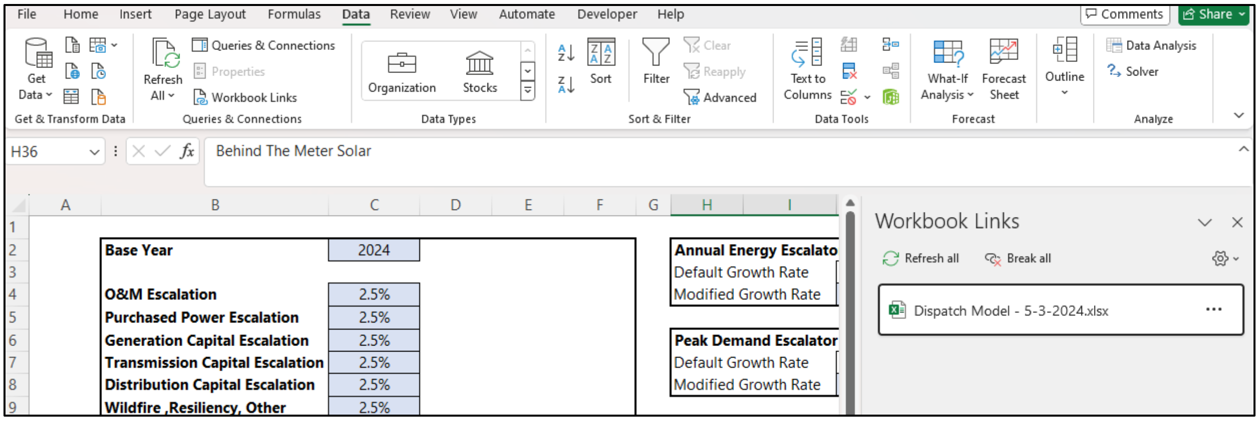
2. Next the assumed growth in net metered solar is doubled from the baseline assumption. This modification can be performed in either the “BTM Solar” tab or the “General Inputs” tab also has a section that can be used to update this input. In this example the BMT solar capacity growth was doubled.

“General Inputs” Tab

Behind The Meter Solar	
Default Growth	93MW
Default Growth Rate	6%
Modified Growth	186MW
Modified Growth Rate	8%

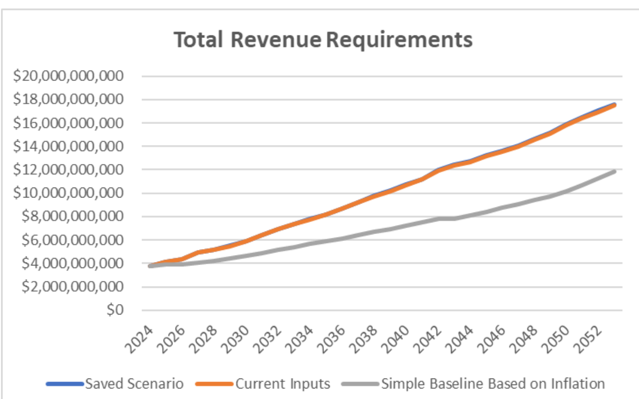
3. Because this scenario includes changes in load or generation the user must open and update the Dispatch Model spreadsheet. This is most effectively done by opening the spreadsheet via the workbook links in the main rate model Data=>Workbook Links => Open Workbooks. The Dispatch Model spreadsheet will automatically update when opened and can then be saved and closed.

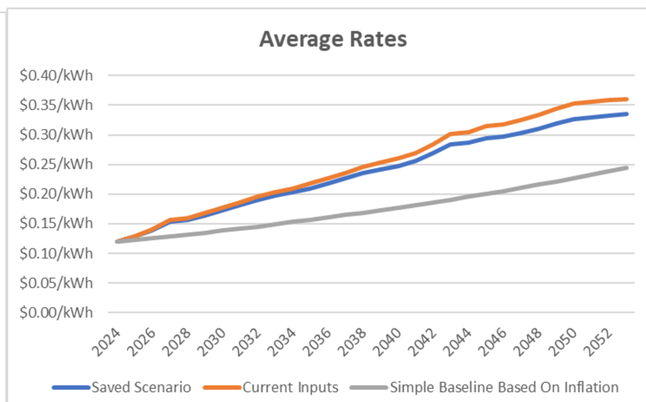
Open Linked Dispatch Model Spreadsheet

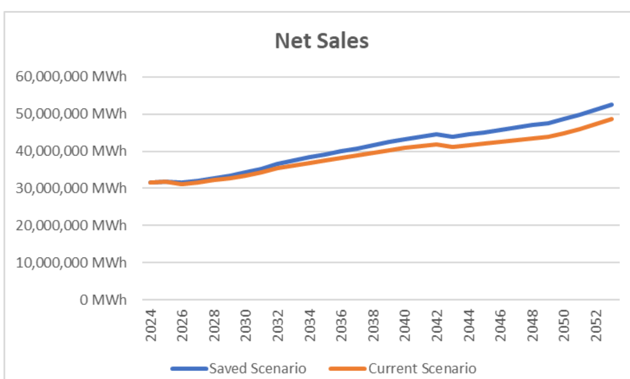


4. The outputs of the two scenarios can then be compared. The results show that revenue requirements are only slightly decreased as a result of increased BTM solar growth. However, because net sales have decreased, average rates are forecasted to be higher.

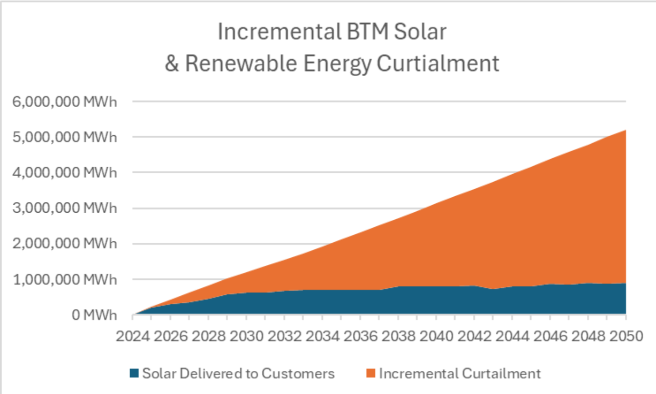
"General Inputs" Tab

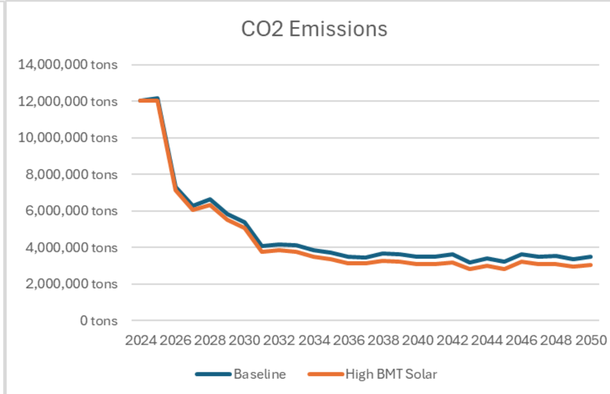






Further details from the "Dispatch Output" tab reveal that the increase in BTM solar generation results in a large increase in the amount of renewable energy curtailed and that the net result is only a small impact on CO2 emissions.


Incremental BTM Solar
& Renewable Energy Curtialment
6,000,000 MWh
5,000,000 MWh
4,000,000 MWh
3,000,000 MWh
2,000,000 MWh
1,000,000 MWh
0 MWh
2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
Solar Delivered to Customers
Incremental Curtailment

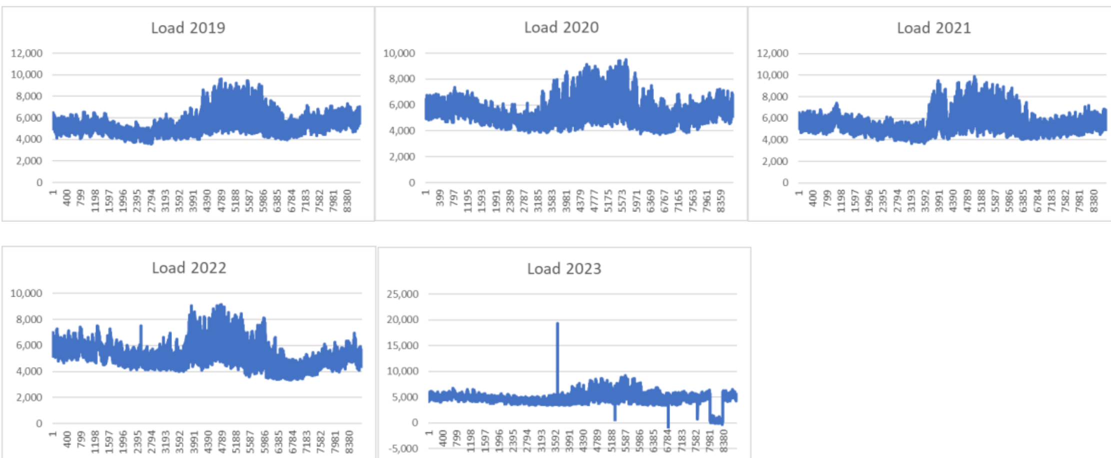

CO2 Emissions
14,000,000 tons
12,000,000 tons
10,000,000 tons
8,000,000 tons
6,000,000 tons
4,000,000 tons
2,000,000 tons
0 tons
2024 2026 2028 2030 2032 2034 2036 2038 2040 2042 2044 2046 2048 2050
Baseline
High BMT Solar

Dispatch Model

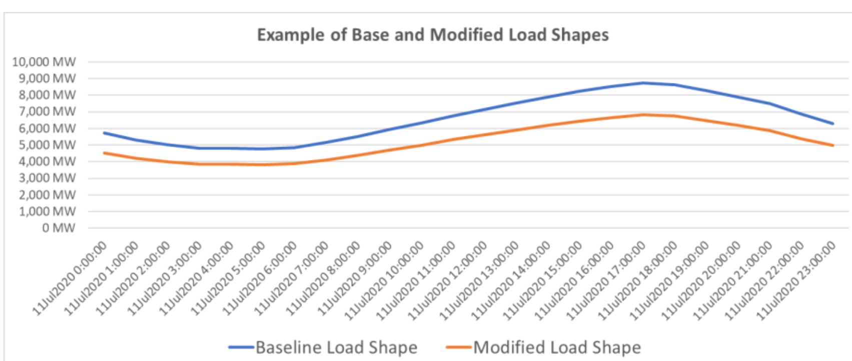
The 30-year rate forecasting model has an associated dispatch model that performs a simplified simulation of the generation dispatch in order to forecast fuel costs in the rate forecast. The dispatch model is intended to be a high-level estimate energy costs and is not as detailed as simulation models used by utilities.

Load Shapes

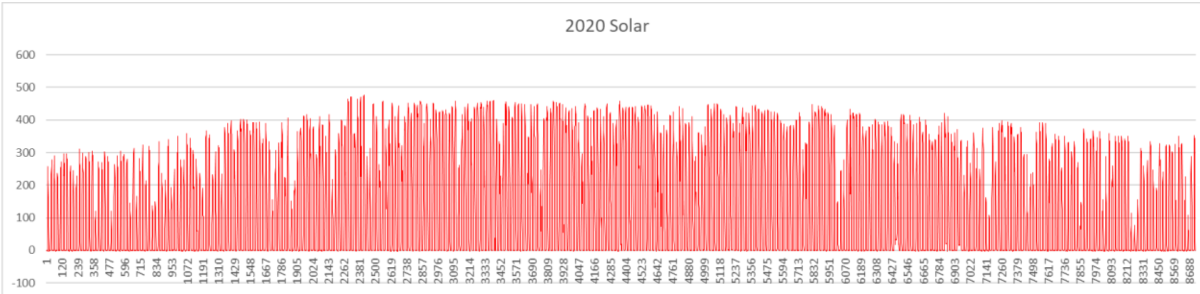
The dispatch model begins with load shapes. The EIA Grid Monitor tool provides hourly load information for several years at the balancing area level. The default model uses the 2020 load shape as it appeared to be the most representative and did not contain obvious data issues like the 2023 shape.

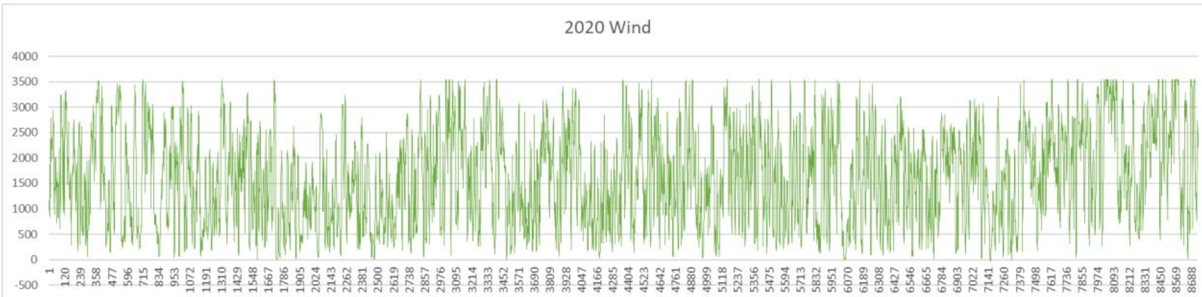


Next the load shape is calibrated to the peak demand and annual energy specified by the user. The following figure illustrates how the baseline load shape is modified to match the target peak and energy for a single July day. Note that because the baseline shape is for the entire Colorado balancing area, the modified shape representing PSCo only is lower.

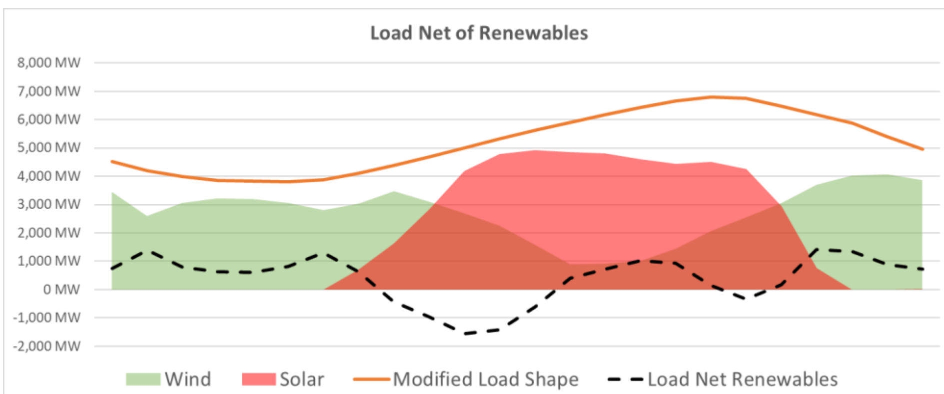


Next wind and solar generation is subtracted from the modified load shape to develop a 'load net renewables shape'. The wind and solar hourly patterns are also sourced from the EIA grid monitor and modified to match the capacity specified by the user.

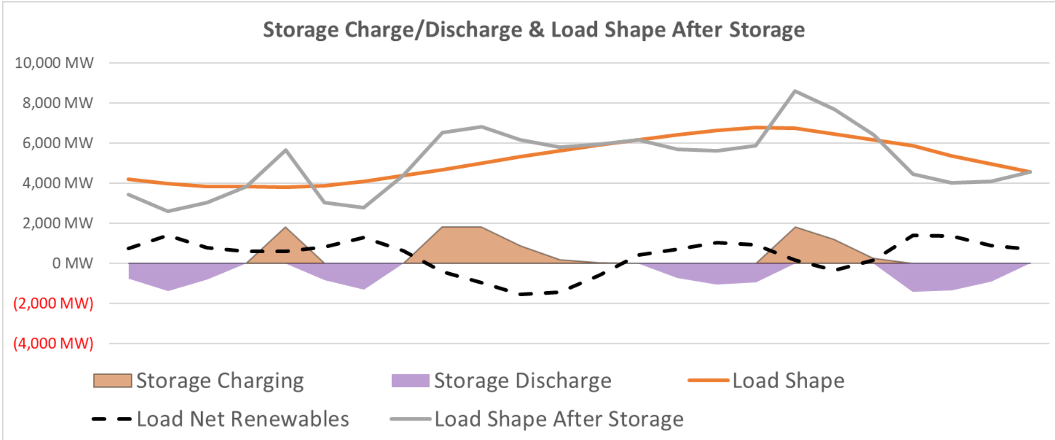




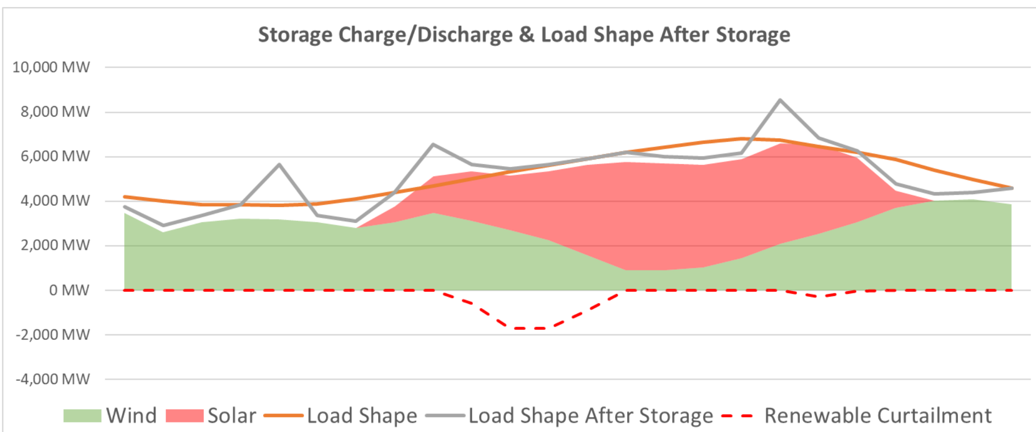
The following figure illustrates a single day in 2030 after the addition of significant amounts of wind and solar resources. The figure shows that there will be periods when total renewable generation exceeds customer demand.



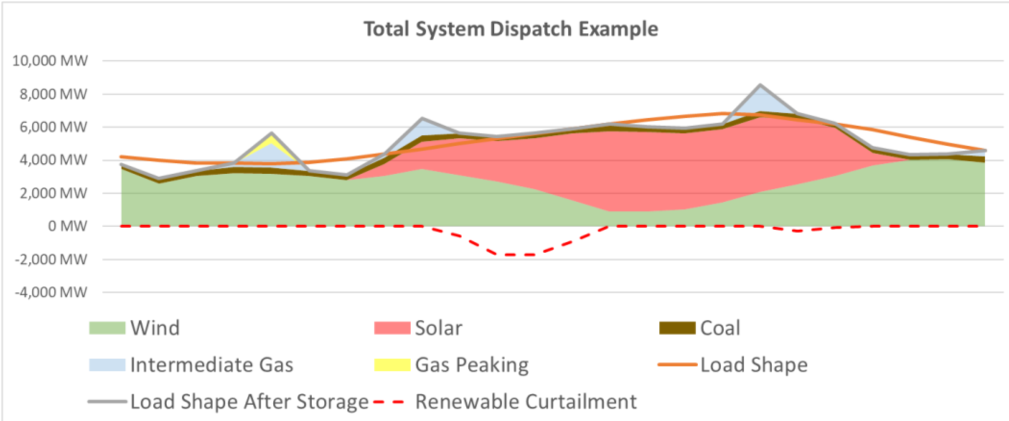
The initial load net renewable shape is used to schedule the dispatch of energy storage resources. The model uses perfect foresight to schedule the charging and discharge of energy storage. The model ranks the net load for the day from lowest to highest and schedules charging during the periods with the lowest net load and discharging for the hours with the highest net load.



After the load shape modified by storage is determined renewables are once again added to the simulation. During periods when renewable generation exceeds load and the charging of storage the model tracks renewable curtailment. For simplicity the model will first curtail solar and then wind. In reality the curtailment strategy of a utility will be much more complex. The model contains an input for minimum thermal generation that reflects the need to have spinning reserves to balance the system and maintain the required voltage. In the figure below this is illustrated by the small distance between the net load shape and the level of renewable generation.



The final step in the dispatch simulation is to fill the remaining net demand with dispatchable resources (coal, intermediate gas, and peaking gas).


Total System Dispatch Example
10,000 MW
8,000 MW
6,000 MW
4,000 MW
2,000 MW
0 MW
-2,000 MW
-4,000 MW
Wind
Solar
Coal
Intermediate Gas
Gas Peaking
Load Shape
Load Shape After Storage
Renewable Curtailment