

Montana Market Outlook and Modeling

1 Key Take Aways

- The cost of renewables and batteries continue to drop dramatically. The growth of renewables is putting downward pressure on energy prices in the Western Electric Coordinating Council (WECC). This makes inflexible thermal resources increasingly uneconomic. Growth in renewables is also increasing the volatility in energy prices (due to the intermittency of production from renewables).
- Ascend sees no evidence to suggest that this trend will reverse and therefore uses decreasing average prices (and implied market heat rates) and increasing price volatility in its models of the WECC going forward. We also model a changing price shape, which is now driven by *net* load (load minus renewables). Lower prices and higher volatility will result in higher values for flexible resources, relative to less flexible resources, in the PowerSimm construct.
- Long-run equilibrium is an economic concept that characterizes a balance of market conditions for new generation to earn “normal” returns. These normal returns are supported through market prices that provide just enough return to pass the threshold condition (for new generation to earn “normal” returns), but not excess levels. Traditionally, long-run price level of the market would support the entrance of a new natural gas combined-cycle (CC) or combustion turbine (CT). Ascend has found the new market dynamics of lower energy prices and short duration price spikes no longer support construction of CCs or CTs. However, long-run equilibrium can be maintained in the near-term with internal combustion engines (ICEs) and starting around 2023, a 4-hour duration battery or battery plus solar plant. These more flexible resources realize normal returns through addressing the high price volatility of the day-ahead and real-time market with fast ramps and no start-up costs and minimum run-times. Ascend’s long-term price forecast reflects the prices (both day-ahead and real-time) that will allow these resources to earn normal returns.
- Montana’s participation in the EIM opens up an avenue for more value for flexible assets
- The emerging trend of pairing solar with batteries follows a pattern seen in other areas in the economy: the digitization of energy, where the supply fundamentals shift from inertia driven power production to power generation without moving parts, perhaps with the exception of wind. This is akin to the transformation of the music industry, which too was driven by inertia machines of phonographs, cassettes, and compact disks. Today, music is purely digital and the improvement in technology has made inertia machines uncompetitive. As with music, this digitalization of supply is expected to lead to a decentralization of supply with more sources of energy supply.

2 DA Forecasted Energy Prices:

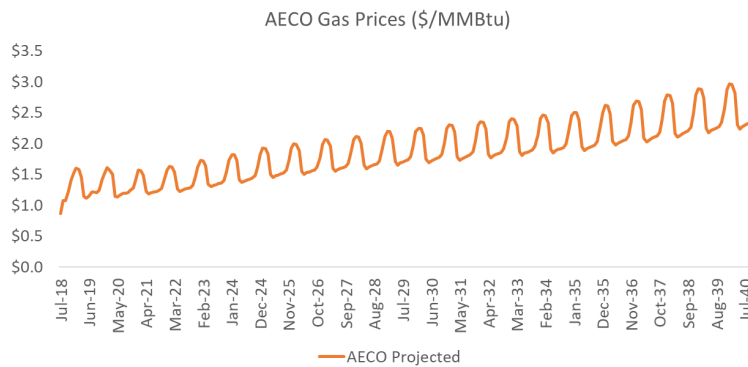
The figures below show the inputs into PowerSimm modeling given energy market fundamentals. The main inputs into spot price modeling are monthly forward power price projections, projections of hourly price shapes, and hourly spot price volatility. The simulations are constrained so that spot prices converge to the forward power price projections, which are derived from fundamental modeling of the WECC bounded by long-run equilibrium conditions and system reliability constraints. The model assumes that renewables will continue to realize technological advances that will support state initiatives for increased renewable production through

enhanced economics that will displace traditional thermal generation resources. Long-run equilibrium conditions ensure that projected wholesale market prices are not too low or too high for new generation resources to earn “normal” returns by operating when power prices are high and shutting down when power prices are low.

2.1 Gas Prices

Gas price projections were provided by NorthWestern for the AECO hub. In the near term, through the year 2022, this forecast uses current prices trading on the futures gas market. After 2022, prices are escalated by EIA’s 2018 AEO annual escalation rates through the remainder of the forecast. Gas prices projected below are shown in Figure 2.1.

Figure 2.1: AECO Gas Price Forecast

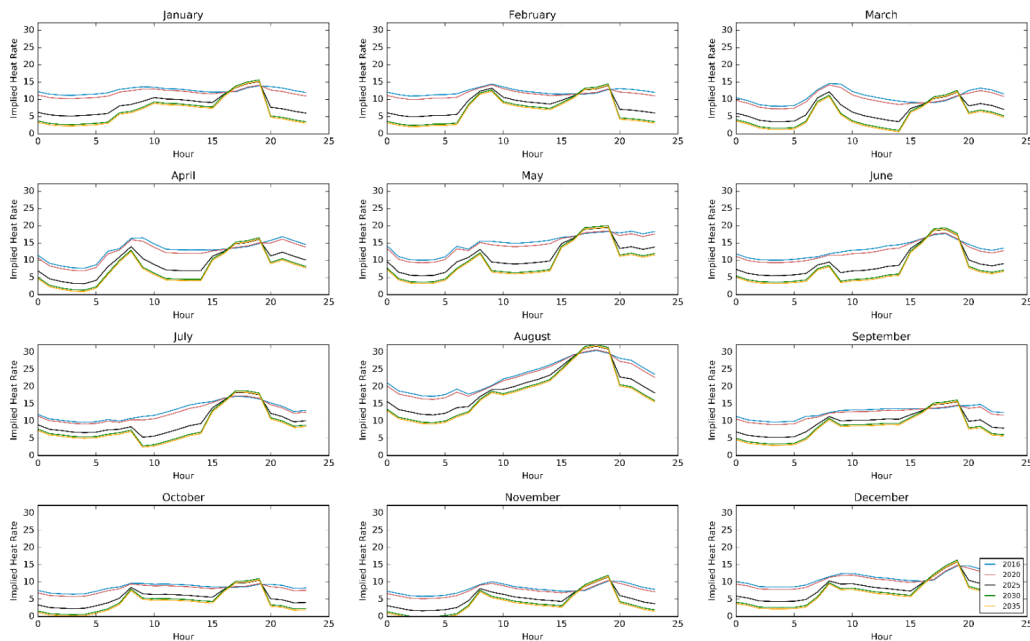


2.2 Power Prices

Forward power price projections are calculated as a product of implied heat rates (MMBtu/MWh) based on market fundamentals and gas price forecasts (\$/MMBtu). Hourly spot power prices are simulated with a co-integrated time series model using the key structural variables of natural gas prices, system loads, and renewable production. Each monthly simulation of hourly spot power prices converges to the monthly forward forecast price of power by scaling the hourly values so that the mean hourly spot price matches the forward power price for that month.

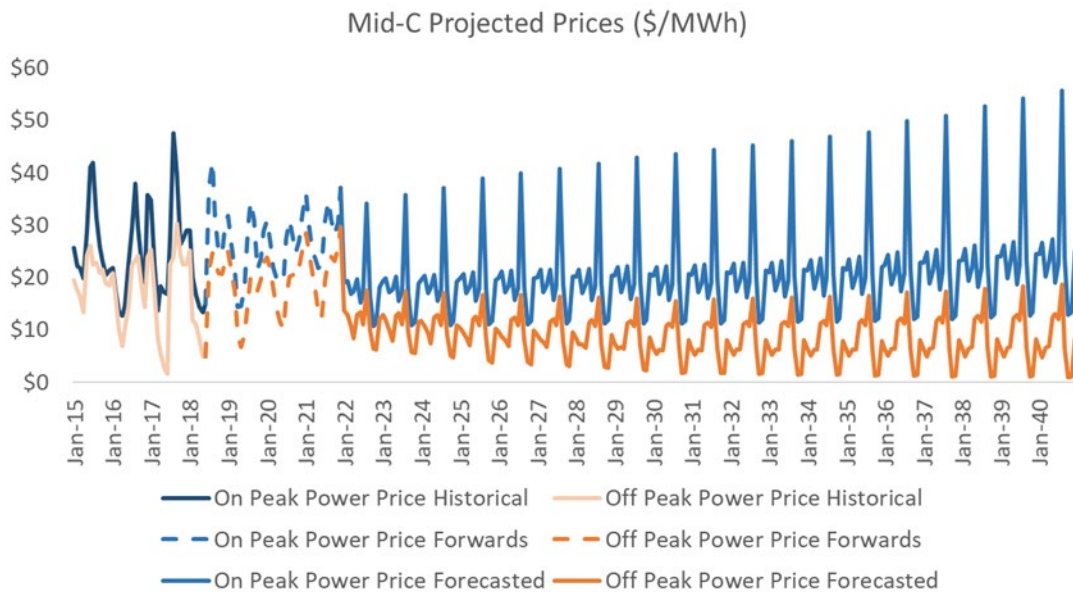
The implied heat rates are predicted based on renewable penetration in the system, as shown in Figure 2.2. This figure shows the power price profile, or implied heat rate, in 2016, and select projected years, by month and hour. The implied heat rate is expected to decline overall in most hours due to increased penetration of wind and additions of solar. Mid-day and nighttime hours will see suppressed prices due to solar and wind/hydro, respectively. The late afternoon hours will see an increase in heat rates as more inflexible thermal comes online when the sun sets. Forecasts are based on a typical hydro year. A drought year would see an increase in the implied heat rate with thermal assets replacing hydro on the margin more frequently.

Figure 2.2: Implied Heat Rates and Price Shapes for 2016, 2020, 2025, 2030, 2035



The implied heat rates are forecasted seasonally, by day of week, and hourly. Projected implied heat rates in 2022 and after are multiplied by the monthly gas prices to forecast out power prices in 2022 onwards, seen in Figure 2.3 below.

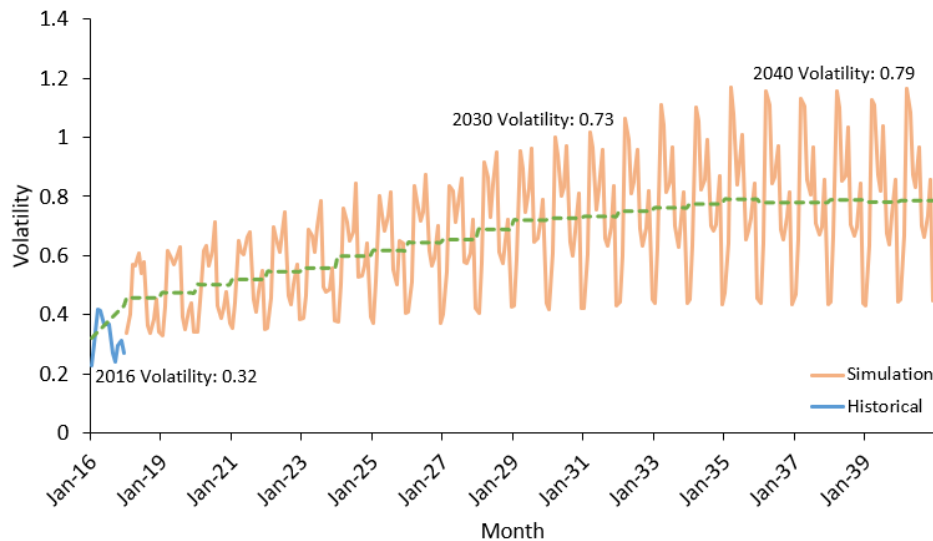
Figure 2.3: Mid-C Projected DA Prices (\$/MWh)



Power price volatility is an important aspect of the power price forecast and is projected to increase as more intermittent renewables come online. The volatility of hourly prices increases in strong correlation with increases in intermittent renewable penetration. That is, after about 20% renewable penetration in the grid, volatility of DA prices follows closely at approximately 0.9 correlation. About ~2.4 GW of derated wind and solar

is projected to be online by 2021 in NWPP¹, causing the supply curve to shift right. Coal plants retiring will shift the curve slightly left, and price volatility will increase further. Figure 2.4 shows the monthly volatility of hourly prices in 2016 and forecasted through 2040. 2017 was omitted due to it being an outlier drought year. Volatility, as measured by the coefficient of variation, is approximately 0.32 as of 2016, and is expected to more than double by 2030 as wind and solar generation more than doubles as well. Ascend takes a conservative approach by projecting that the increasing rate of volatility proceeds more slowly after 2030, as fast-ramping resources such as batteries will be able to dampen volatility by reacting quickly to price signals and thereby arbitraging between peaks and valleys in real-time prices.

Figure 2.4: Projected Day-Ahead Price Volatility at Mid-C



Increasing hourly spot volatility will also have a detrimental impact on traditional inflexible assets. These assets, such as coal plants and combined cycle gas plants, will not be able to ramp quickly enough to provide reliability to the grid nor capture high prices on a more granular time scale. PowerSimm incorporates the physical start-up attributes of each asset to accurately model future dispatch schedules. The dispatch optimization module will naturally select assets with flexible ramping capabilities due to their lower start-up costs and reduced physical constraints. In addition, higher-cost assets may not recover costs from the energy market as they used to if high price periods are not sustained (due to increased volatility). Assets with long start-up times and high start-up costs may miss the high price period and would be “out-of-the-money” before they fully come on line. These economic considerations are included in PowerSimm’s optimization logic and the effects are shown in the dispatch results.

3 Evolving Generation Mix:

3.1 Need for New Capacity Mix in the West

A review of current Integrated Resources Plans (IRPs) for WECC utilities outside of California indicates a need for capacity in the region. While preferred least-cost resources differ between utilities, the common element is that Demand Side Management (DSM), including energy efficiency and demand response, is not believed to be sufficient to mitigate load growth over the planning horizon. In each IRP studied, the contribution toward the

¹ SNL Generation Supply Curve

reserve margin from DSM is smaller than the contribution from both renewable and peaking resources. Furthermore, as resource intermittency increases, additional fast-response flexible capacity is needed to respond to rapid changes in supply.² Large utilities like PacifiCorp plan to replace energy through installing approximately 3 GW of new solar and wind energy and about 1 GW of re-powered wind energy while at the same time retiring 2.7 GW of coal by 2040³. With these planned retirements, PacifiCorp faces a capacity deficit of 220MW in 2022 and 2 GW by 2036⁴. Similarly, Idaho Power, Puget Sound Energy, and Arizona Public Services all have significant capacity needs ranging from 200MW to 1000MW in 2022 as shown in Figure 3.1. Wind was de-rated at 20% and solar was de-rated at 15%.

Figure 3.1: Cumulative Capacity Addition in the West

Cumulative Capacity Additions in Studied IRPs [MW]																				
Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Puget Sound Energy																				
Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	-	-	-	-	-	-	-	-	-	717	717	717	717	717	717	717	717	717	717	1,195
Wind (de-rated)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar (de-rated)	-	-	-	-	-	40	40	40	40	57	57	57	57	57	57	57	57	57	57	73
Idaho Power																				
Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300	300	-	-
Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	36	72	72	126	180	-	-
Wind (de-rated)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar (de-rated)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PacifiCorp																				
Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	-	-	-	-	-	-	-	-	-	-	-	-	200	636	636	636	677	1,313	1,313	1,313
Wind (de-rated)	-	-	-	220	220	220	220	220	220	220	220	220	220	237	237	237	237	237	237	402
Solar (de-rated)	-	-	-	-	-	-	-	-	-	-	2	17	17	35	71	105	112	156	158	-
Portland General																				
Base	290	317	317	370	Outside IRP Forecast Horizon															
Peaking	8	12	16	20	Outside IRP Forecast Horizon															
Wind (de-rated)	-	103	103	103	Outside IRP Forecast Horizon															
Solar (de-rated)	-	-	-	-	Outside IRP Forecast Horizon															
Arizona Public Services																				
Base	-	-	-	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	1,087	4,090	-	-	-	-
Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable	-	-	-	9	9	9	9	9	9	9	9	9	9	9	9	9	27	-	-	-

3.2 Shifting Supply

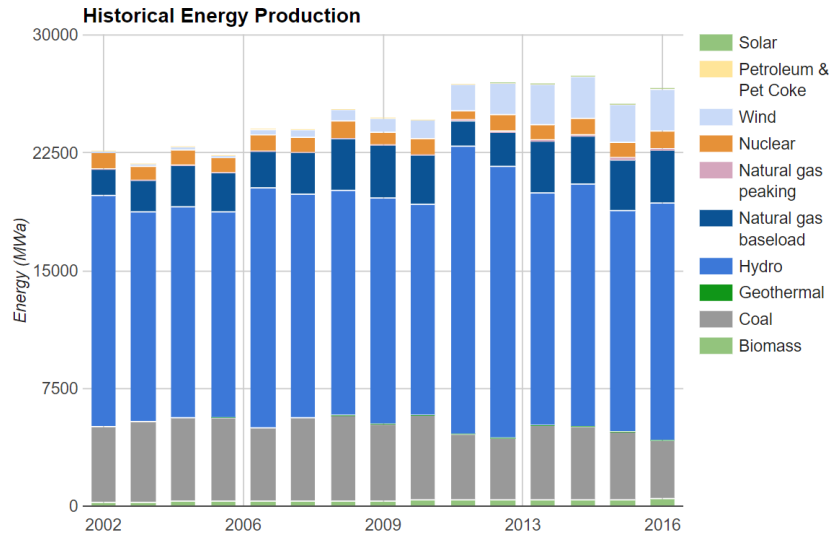
In the North West Power Pool (NWPP), which consists of Washington, Montana, Idaho, and Oregon, generation from coal, hydro, and natural gas have remained relatively constant over the last decade. Figure 3.2 shows the historical annual energy production in NWPP since 2002. Installed wind capacity has been growing since 2006. Hydro and natural gas generation have historically been the main sources of power to the NWPP, with hydro comprising 54% of the current generation capacity while natural gas (baseload and peaking) make up ~15% of the total capacity mix. Wind installations have been on the rise and currently comprise 14.5% of the total capacity mix in NWPP.

² The need for new capacity and for increased flexibility is shown in many of the published IRPs discussed in Appendix B.

³ Appendix B3

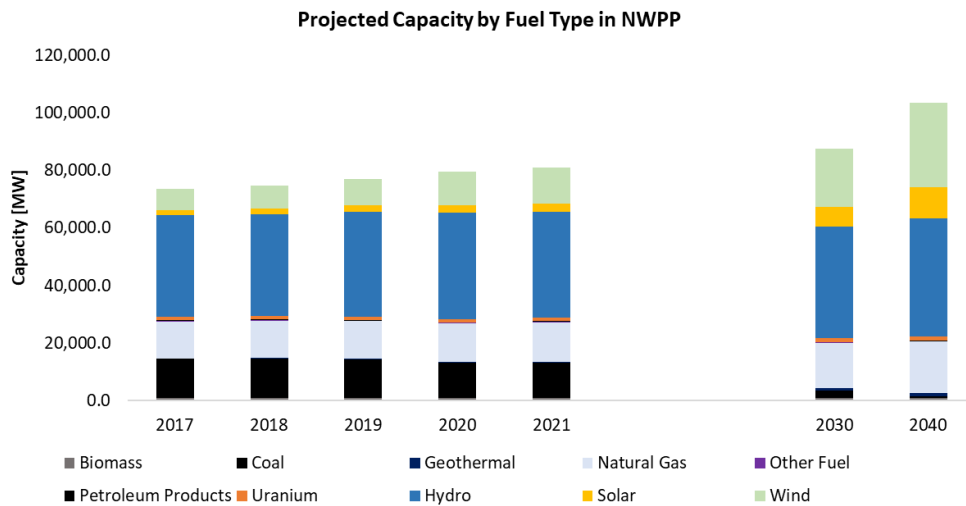
⁴ Appendix B4

Figure 3.2: Historical Annual Energy Production in NWPP since 2002



The expected reduction in renewable supply costs and a conscious drive toward 100 percent renewable supply portfolios results in significant additions of PV solar and onshore wind in the NWPP. Figure 3.3 shows the slow rise of wind, solar, and hydro assets. Ascend utilizes SNL’s capacity forecast in the region through 2021, then extrapolates the capacity through 2040. SNL predicts that ~1.3 GW of solar and ~4.9 GW of wind will come online by 2021. Ascend further predicts an even greater increase of 9 GW of nameplate solar and 17 GW of nameplate wind capacity will come online by 2040 due to the region’s capacity need, rapidly changing economics, and coal retirements.

Figure 3.3 Projected Capacity by Fuel type in NWPP through 2040



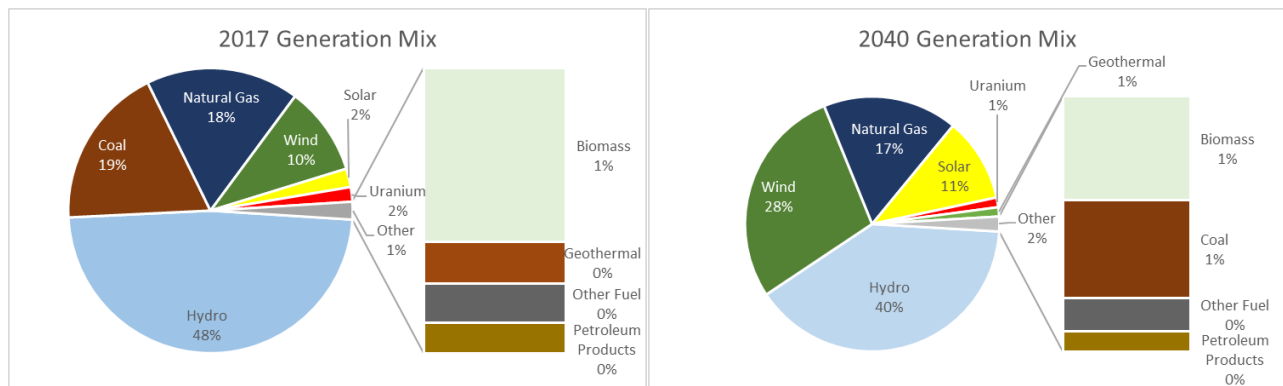
In the next eight years, the EIA predicts that coal-fired generation capacity will drop 26% from today’s 13.6 GW to just over 10 GW. Expected retirements in this time period include Units 1 & 2 at the 2.1 GW Colstrip power plant in Montana and the 1.3 GW Centralia power plant in Washington, which is expected to switch both its

units over to natural gas by 2025. Beyond eight years, there are more coal plants set to retire, such as the 762 MW Dave Johnston plant in Wyoming in 2027. Overall, approximately 5 GW of coal is expected to retire in the region by 2030.

Ascend conservatively assumes that in addition to officially announced retirements dates, plants will retire at an age of 50 years old, or will retire if they are unable to remain consistently operational in the modern market, having variable O&M above \$25/MWh, given an influx of renewables and a cheaper gas price forecast. On average, the plants on the margin can operate with a VOM at ~\$18/MWh⁵, and even with declining power prices, coal would not run at peak demand compared to more flexible and faster gas units. Ascend predicts ~11 GW of retirements by 2040⁶.

With increased new capacity built to meet deficits in the next 10 years in the region, and with greater coal retirements, Ascend projects the supply for 2030 and 2040 to be as shown in Figure 3.4⁷.

Figure 3.4: Energy mix in 2017 and projected mix in 2040



With solar projected to increase 5X by 2040, and wind installations projected to almost triple, both at zero variable cost, these units will more frequently be the marginal unit, shifting power prices down. Section 3.3 discusses the impact of high renewable integration on power prices.

3.3 Impact of High Renewable Integration

Most intermittent renewable power in NWPP is wind, with penetration levels in 2017 reaching 23% in any given hour. Wind and solar, at effectively zero variable cost, shift the supply stack to the right and reduce power prices. Over the past 3 years, power prices have declined with the increase in wind penetration in any given hour. Figure 3.5 shows this declining trend in NWPP and SPP. In certain regions, like CAISO with high renewables, or SPP with high wind, corresponding prices tend to become negative after approximately 55% renewable generation in any given hour.

⁵ SNL Generation Supply Curve data

⁶ Full table of coal retirement projections in Appendix A

⁷ Data from SNL.com through 2021. Appendix C shows SNL 2017 generation supply curve as well as Ascend forecasted 2030 and 2040 generation supply curves.

Figure 3.5: Day-Ahead (DA) Prices and Wind Penetration as a percentage of load in any hour per month

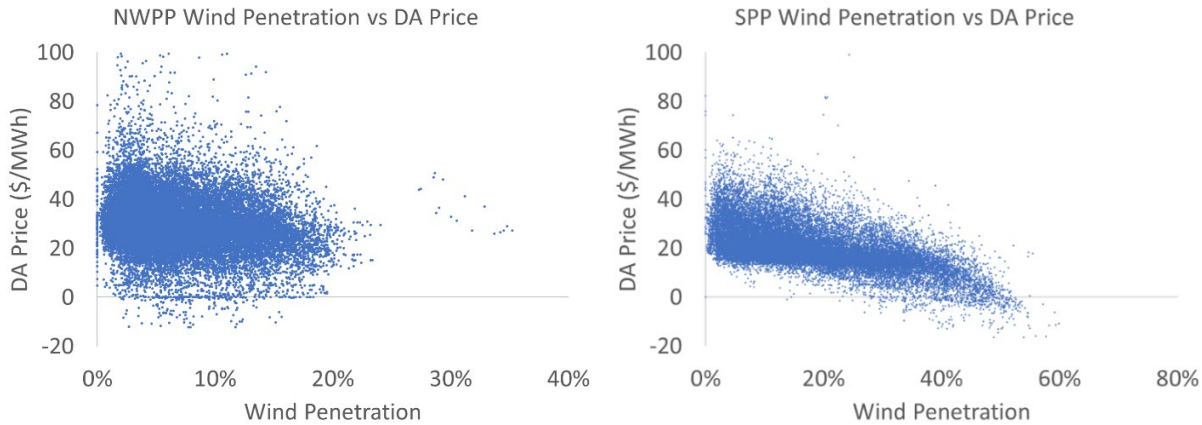
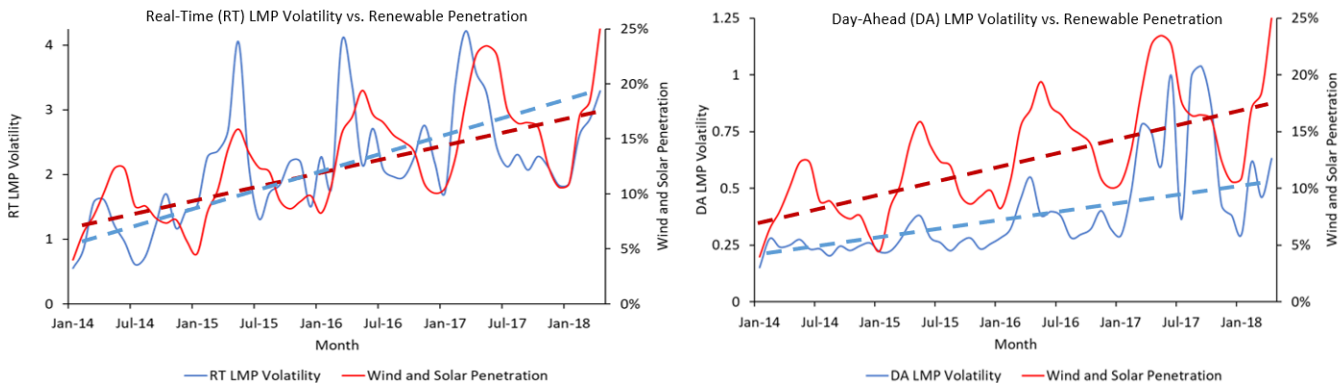


Figure 3.6 below shows the correlation between increased renewable penetration in the system and volatility in SP15 power prices, from 2015-2017 in the CAISO market. In both the real-time (RT) and day-ahead (DA) markets, price volatility tends to follow renewable generation more closely when renewable penetration in the system increases from 10% to 20%. Currently, the northwest region sees renewable penetration as high as 23% in any given hour, and this has been increasing. As intermittent renewables grow, volatility will grow accordingly as well.

Figure 3.6: Volatility in RT Prices (2015-2017)



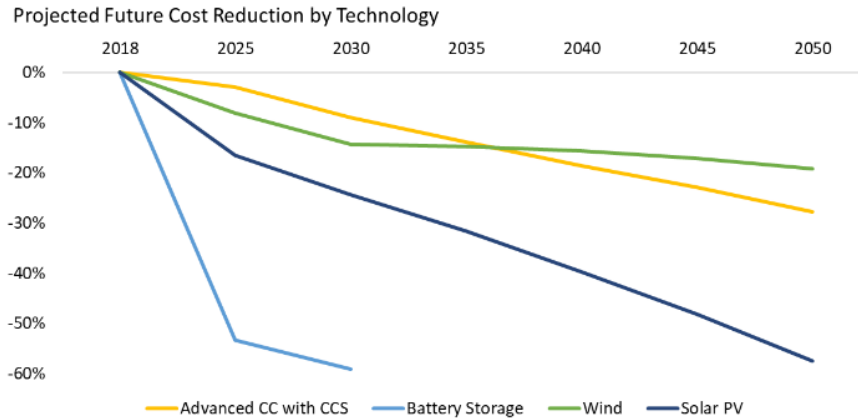
4 Long-Run Equilibrium

4.1 Technology Costs

Technology costs of wind and solar have been declining steadily and forecasts by Bloomberg and other groups expect this trend to continue. The decreases are particularly significant for battery technology. Figure 4.1 shows

the reduction of overnight capital costs in advanced combined cycle (CC), solar, wind, and battery technologies⁸. Costs of advanced CCs are expected to drop by 10-15% in the next 10 years, while battery costs are expected to decline by 60% in the next 5-10 years. Wind and solar costs are expected to decline overall by 20% and 30%, respectively.

Figure 4.1: Overnight Capital Costs by Technology Type



As capital costs for renewables are decreasing, PPA costs are declining for utility scale wind, solar, and hybrid resources (e.g., wind+battery and solar+battery). Xcel Energy in Colorado issued an all source RFO for energy and capacity in 2017. Figure 4.2 shows Xcel Utility’s RFO Bid results. Xcel received 430 bids with prices coming in much lower than expected. Wind bids were lowest cost with the median bid price was \$18.10/MWh for wind and \$21/MWh for wind + battery. The median bid price for solar was \$29.50/MWh and solar + battery was \$36/MWh.

⁸ EIA AEO Outlook: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

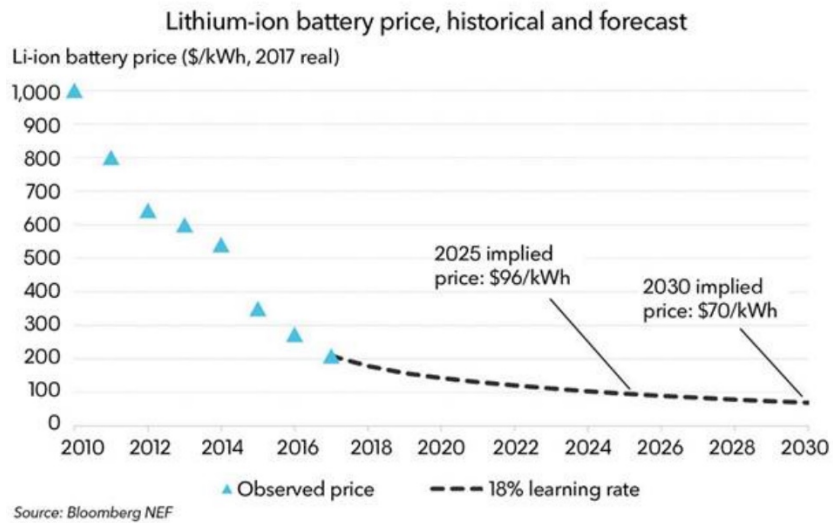
Figure 4.2: Xcel RFO Bid Results

XCEL RFO Bid Results Summary

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	\$4.80	\$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	\$6.20	\$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	\$6.70	\$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	\$11.30	\$/kW-mo
Compressed Air Energy Storage	1	317	1	317	\$14.60	\$/kW-mo
Wind	96	42,278	42	17,380	\$18.10	\$/MWh
Wind and Solar	5	2,612	4	2,162	\$19.90	\$/MWh
Wind with Battery Storage	11	5,700	8	5,097	\$21.00	\$/MWh
Solar (PV)	152	29,710	75	13,435	\$29.50	\$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	\$30.60	\$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	\$36.00	\$/MWh
IC Engine with Solar	1	5	1	5	\$50.00	\$/MWh
Waste Heat	2	21	1	11	\$55.40	\$/MWh
Biomass	1	9	1	9	\$387.50	\$/MWh
Total	430	111,964	238	58,284		

Figure 4.3 shows Bloomberg New Energy Finance’s forecast of battery module costs through 2030. Costs are expected to about half by 2025⁹.

Figure 4.3: Battery Technology Cost Forecast



⁹ Bloomberg New Energy Finance (BNEF)

5 Appendices

Appendix A Coal Plant Predictions:

Table A1: 2030, 2040 Retiring Coal Plant Predictions

In order, the following criteria were used to determine whether each coal plant would retire by 2030 and 2040:

1. Is the retirement date known, officially or unofficially?
2. Will the coal plant be at least 50 years old?
3. Is the coal plant's variable O&M \$25/MWh or greater?

Plant Name	Summer Capacity (MW)	2030 Justification	2040 Justification
Dry Fork Station	88.236	--	--
Amalgamated Sugar	5	--	--
Laramie River Station	60.534	--	50+ years old
Laramie River Station	60.534	--	50+ years old
Laramie River Station	60.534	--	50+ years old
Amalgamated Sugar	2.3	50+ years old	50+ years old
Dave Johnston	330	Retirement Date Known	Retirement Date Known
Amalgamated Sugar	1.2	--	--
Dave Johnston	220	Retirement Date Known	Retirement Date Known
Antelope Valley	112.5	--	50+ years old
Kennecott Utah Copper	75	--	--
Antelope Valley	112.5	--	50+ years old
Dave Johnston	105	Retirement Date Known	Retirement Date Known
Wygen 3	37	--	--
Dave Johnston	105	Retirement Date Known	Retirement Date Known
Leland Olds	111.25	50+ years old	50+ years old
Leland Olds	55.5	50+ years old	50+ years old
Wyodak	332	50+ years old	50+ years old
Bonanza	458	Retirement Date Known	Retirement Date Known
Hunter	460	50+ years old	50+ years old
San Juan	35.6421	--	--
Colstrip	740	--	50+ years old
Hunter	430	50+ years old	50+ years old
Colstrip	629	--	50+ years old
Hunter	471	50+ years old	50+ years old
Colstrip	307	Retirement Date Known	Retirement Date Known
Colstrip	307	Retirement Date Known	Retirement Date Known
FMC Westvaco ST	3.5	50+ years old	50+ years old
FMC Westvaco ST	3.5	50+ years old	50+ years old
FMC Westvaco ST	4	50+ years old	50+ years old
FMC Westvaco ST	10.50	years old	50+ years old
FMC Westvaco ST	11.5	50+ years old	50+ years old
FMC Westvaco ST	14.1	50+ years old	50+ years old
Hardin Generator Project	107	--	--
Colstrip Energy LP	35	--	--
Thompson River	12	--	--
George Neal South	29.2516	--	--
TS Power Plant	218.4	--	--
Huntington	459	50+ years old	50+ years old
Huntington	450	50+ years old	50+ years old
Centraia	670	Retirement Date Known	Retirement Date Known
Centraia	670	Retirement Date Known	Retirement Date Known
Yellowstone Energy Cogen (Billings Generation Inc)	68	--	--
Intermountain	225.45	--	50+ years old
General Chemical - Wyoming	15	--	--
General Chemical - Wyoming	15	--	--
Intermountain	225.45	Above \$25/MWh Variable O&M	50+ years old
Naughton	156	50+ years old	50+ years old
Naughton	201	50+ years old	50+ years old
Naughton	330	50+ years old	50+ years old
Craig (Yampa)	82.5184	Retirement Date Known	Retirement Date Known
Craig (Yampa)	82.5184	Above \$25/MWh Variable O&M	Above \$25/MWh Variable O&M
Big Stone	53.799	Above \$25/MWh Variable O&M	Above \$25/MWh Variable O&M
Hayden	33.012	Above \$25/MWh Variable O&M	Above \$25/MWh Variable O&M
Cholla	380	Above \$25/MWh Variable O&M	Above \$25/MWh Variable O&M
Jim Bridger	527	50+ years old	50+ years old
Hayden	43.855	Above \$25/MWh Variable O&M	Above \$25/MWh Variable O&M
Jim Bridger	531	50+ years old	50+ years old
Sunnyside Cogeneration	51	Above \$25/MWh Variable O&M	Above \$25/MWh Variable O&M
Jim Bridger	523	50+ years old	50+ years old
Jim Bridger	530	50+ years old	50+ years old
Boardman	526.5	Retirement Date Known	Retirement Date Known
R.M.Heskett Generating Station	37.4	Above \$25/MWh Variable O&M	Above \$25/MWh Variable O&M
North Valmy Station	268	Retirement Date Known	Retirement Date Known
North Valmy Station	254	Retirement Date Known	Retirement Date Known
R.M.Heskett Generating Station	14.75	Above \$25/MWh Variable O&M	Above \$25/MWh Variable O&M

Appendix B: Capacity Evolution in WECC

Currently existing IRPs demonstrate the need for capacity in the region. While the least-cost resources identified in these IRPs differ between utilities, the common element is that DSM is not enough to mitigate load growth over the planning horizon. Furthermore, as resource intermittency increases, additional peaking capacity is needed to respond to changes in supply. This flexibility is shown in many of the published IRPs

Currently many released IRPs predict that there will be an inflection point in the early 2020s. Between 2020 and 2023, almost all studied IRPs plan to install large quantities of energy in those years to correspond with forecasted coal generation shutdowns. A second round of coal station shutdowns is forecasted to occur in the early 2030s, and this is also reflected in the IRPs with a corresponding plan to install new, predominantly renewable generation, in those years.

Resource Plans by Utility

B.1 Puget Sound Energy¹⁰:

Peak load in PGE service territory is projected to grow by over 1400MW by 2037. Using DSM PGE plans to shave the peak to 5664MW. The balance of this peak demand is predominantly filled by peaking resources and renewables.

Cumulative Nameplate Capacity of Resource Additions

	2023	2027	2037
Conservation (MW)	374	521	714
Demand Response (MW)	103	139	148
Solar (MW)	265	377	486
Energy Storage (MW)	50	75	75
Redirected Transmission (MW)	188	188	188
Baseload Gas (MW)	0	0	0
Peaker (MW)	0	717	1,195

B.2 Idaho Power¹¹:

Idaho Power forecasts that without the installation of new capacity, they will begin to have capacity deficits by 2029, with mean power deficits growing to the over 600MW in 2036. Peak deficits are projected to occur by 2026 and grow to almost 1000MW by 2036. To resolve this, Idaho Power is proposing to add peaking capacity in the form of reciprocating engines as well as generic generation in combined cycle combustion turbines. They also plan to install additional capacity to allow for increased transactional supply of power.

¹⁰ PGE IRP - <https://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx>

¹¹ Idaho Power IRP - <https://www.idahopower.com/energy/planning/integrated-resource-plan/>

Date	Resource	Installed Capacity
2026	B2H	500 MW transfer capacity, Apr–Sep 200 MW transfer capacity, Oct–Mar
2031	Reciprocating engines	36 MW
2032	Reciprocating engines	36 MW
2033	CCCT (1x1)	300 MW
2035	Reciprocating engines	54 MW
2036	Reciprocating engines	54 MW

B.3 Pacificorp¹²:

Pacificorp does not face large capacity deficits over the planning horizon, in part due to their acquisition of energy through long term bi-lateral contract. Despite their lack of demand driven development, they are still choosing to overhaul their portfolio for economic reasons. They are steering away from thermal generation and toward renewable resources. In total, they plan to put almost 3GW of new/repowered wind online and 1GW of new solar online by 2036. Over the same period, coal generation will be decreased by 2.7GW and a net of about 1GW of natural gas generation will be installed. This new capacity allows them to easily hit their load demand targets and to maintain their 13+% reserve margin.

Table 1.1 – 2017 IRP Preferred Portfolio Summary (Nameplate MW)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	Total
New Resources																					
Summer FOT	500	521	878	807	799	916	844	885	1,042	978	1,040	1,575	1,575	1,566	1,575	1,575	1,575	1,575	1,575	1,539	n/a
Winter FOT	281	332	273	307	319	308	306	287	348	351	297	412	551	516	490	451	437	477	479	766	n/a
DSM - Energy Efficiency	154	128	131	122	123	114	118	118	112	111	109	102	96	95	96	83	75	65	63	63	2,077
DSM - Load Control	0	0	0	0	0	0	0	0	0	0	0	193	140	5	3	3	3	4	3	12	365
Wind	0	0	0	0	1,100	0	0	0	0	0	0	0	0	0	85	0	0	0	0	774	1,959
Solar	0	0	0	0	0	0	0	0	0	0	0	11	97	0	118	237	226	48	291	13	1,040
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	30	0	0	0	0	0	0	0	30
Natural Gas	0	0	0	0	0	0	0	0	0	0	0	0	200	436	0	0	677	0	0	0	1,313
Existing Resources																					
Reduced Coal Capacity	0	0	(280)	0	(387)	0	0	0	0	(82)	0	(762)	(354)	(357)	(78)	0	(359)	0	(82)	0	(2,741)
Reduced Gas Capacity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(358)	0	0	0	(358)
Repowered Wind Capacity	0	0	794	111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	905

* Note: Energy efficiency resource capacity reflects projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource. FOTs are short-term firm market purchases delivered only in the year shown. Reductions in existing coal and natural gas capacity are shown in the year after the assumed year-end retirement date (909 MW of existing coal capacity is assumed to retire year-end 2036, which would be reflected beginning 2037). Repowered wind capacity reports the amount of existing wind capacity assumed to be repowered in the preferred portfolio.

¹² Pacificorp IRP -

https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_Volume1_IRP_Final.pdf

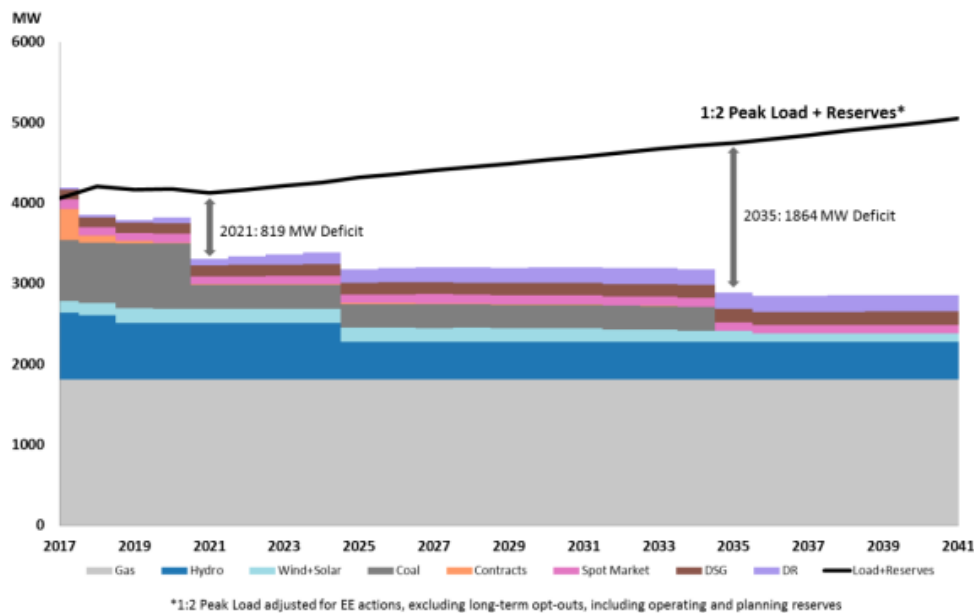
B.4 Portland General Electric¹³:

PGE forecasts that due to demand increases, retirement of coal resources, contract expiration, and decreasing availability of hydro resources, a demand deficit will emerge in the near future, growing to 819MW by 2021 and to 1864MW by 2035. The short term actions to address this forecasted deficit focus primarily on installation of renewable and efficient capacity as well as demand side actions with reductions through DSM and energy efficiency programs.

TABLE 13-1: Preferred portfolio cumulative resources

Preferred Portfolio Cumulative Resources*	Action Plan Time Horizon				
	2017	2018	2019	2020	2021
Efficient Capacity 2021 (Nameplate Capacity, MW)					
Energy Efficiency (EE)	45	89	131	168	202
Demand Response (DR)	26	29	32	70	78
Conservation Voltage Reduction (CVR)	-	0.43	0.86	1.29	1.74
PNW Wind	-	515	515	515	515
Generic Capacity	-	290	317	317	370
Efficient Capacity	-	-	-	-	389
Dispatchable Standby Generation (DSG)	4	8	12	16	20

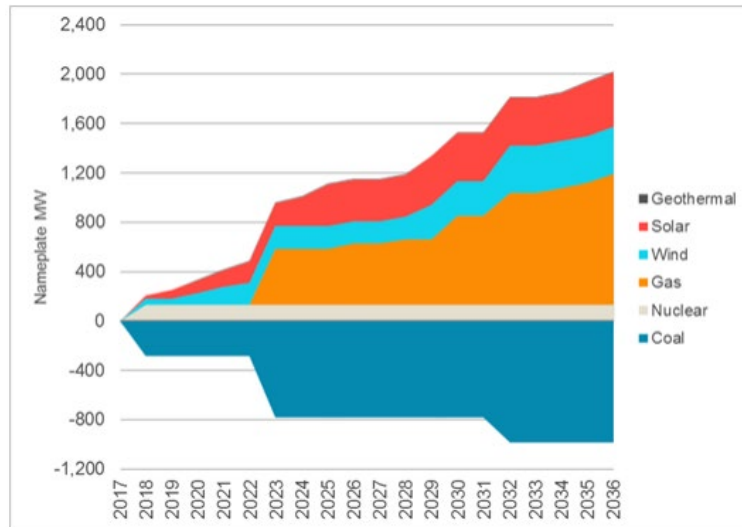
FIGURE 5-1: PGE's estimated annual capacity need



¹³ PGE IRP - <https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp>

B.5 PNM – Public Service Company of New Mexico^{14 15}:

PNM’s IRP calls for a significant elimination of coal from the generation portfolio in 2022 and following that a complete elimination of coal resources in 2031 when an existing supply contract expires. Absent that contract it would be economically preferable to transition away before that date. To replace this energy and to meet future load demands PNM found that the most economic option was to install a combination of solar and flexible natural gas peaking CTs. PNM considers battery storage to be an option, but it is contingent on the economics of proposals received over the next four years.



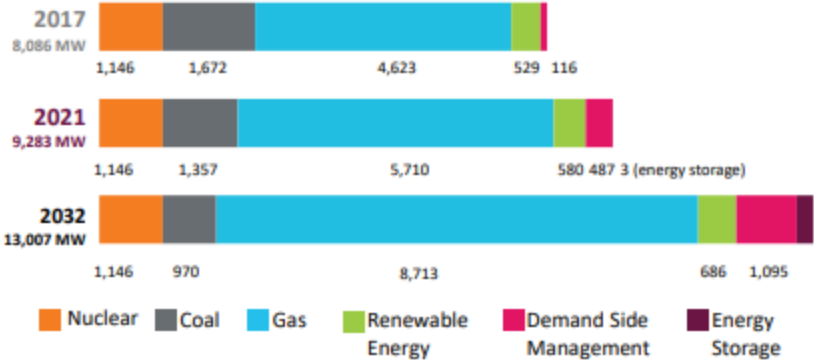
B.6 Arizona Public Services¹⁶:

APS is forecasting a large demand increase over their planning window with demand forecasted to grow from 8,086MW in 2018 by 4,921MW to 13,007 by 2032. To accomplish this, APS plans to install over 4GW of gas generation and to implement almost 1GW of DSM. APS also uniquely plans to install a large amount of energy storage. The chosen portfolio was configured to maximize the flexibility of the resources to respond to an increasingly dynamic supply and demand. In addition the flexible as well as to give APS the ability to interface better with the rest of the WECC, and in particular to interface with CAISO’s EIM.

¹⁴PNM IRP Executive Summary - https://www.pnm.com/documents/396023/396193/PNM+2017+IRP_Executive+Summary.pdf/992f1578-8eb1-4454-a51e-7ea19cf39833

¹⁵PNM IRP- <https://www.pnm.com/documents/396023/396193/PNM+2017+IRP+Final.pdf/eae4efd7-3de5-47b4-b686-1ab37641b4ed>

¹⁶ APS IRP - <https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf>



Appendix C.1: Generation Supply Curves

2017 Generation Supply Curve with minimum, average, and peak load

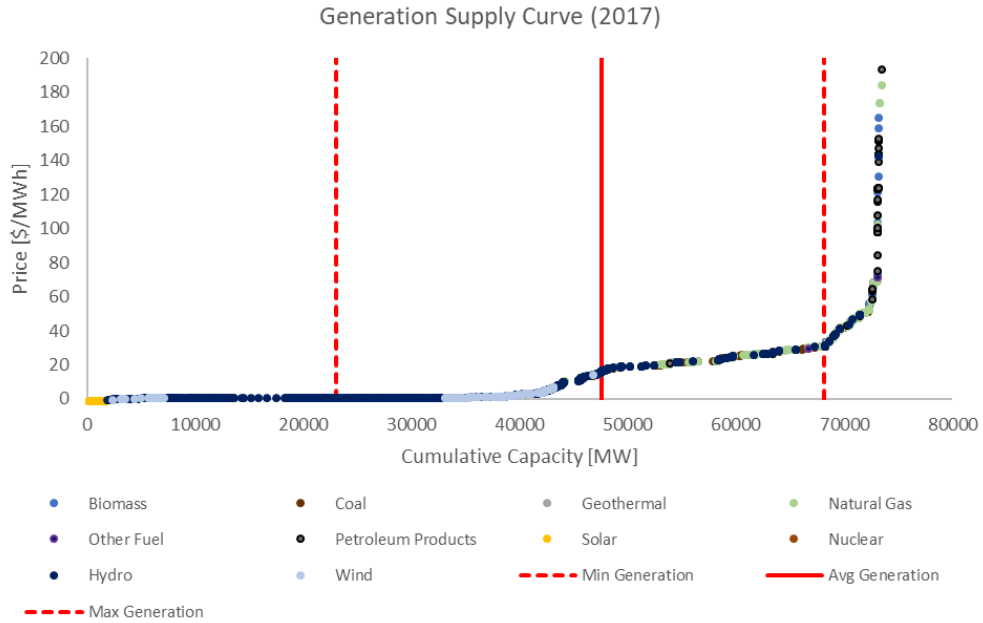


Figure 6: Generation Supply Curves for 2030 and 2040

