Arizona's Residential Utility Consumer Office

Residential Ratepayer Cost Analysis
of
Clean Energy for a Healthy Arizona
ballot initiative

Executive Summary

RUCO conducted an assessment of the *Clean Energy for a Healthy Arizona* ballot initiative, which requires 50% renewable energy by 2030. The assessment focused on impacts to APS and TEP customers. Notably, SRP, which powers nearly 35% of Arizona's ratepayers, is not affected by this initiative.

The initiative would require significant investment in new renewable energy resources and other grid infrastructure, by those utilities affected by the initiative. For APS, we estimate that approximately 3000 MW of additional large scale solar, 2100 MW of distributed solar, and 1400 MW of wind resources would be necessary to meet the requirement. For TEP, over 550 MW of additional large scale solar, 570 MW of distributed solar and 625 MW of wind would be needed. Additionally, this initiative would also require a substantial investment in new transmission and energy storage to deliver the energy when and where it is needed.

The overall generation cost to APS customers was estimated to be approximately $2.8 billion more (net present value, through 2032) than APS' 2017 resource plan.[1] This equates to an annual bill increase for a typical residential customer of at least $630 by 2030, compared to today's rates. The overall cost to TEP customers was estimated to be about $0.5 billion more (net present value, through 2032) than TEP's 2017 resource plan. This equates to an annual bill increase for an average residential customer of at least $449 by 2030, compared to today's rates. Smaller utilities will likely have a more difficult time dealing with the effects of the initiative.

Significantly, RUCO estimates that the ballot initiative will cause the Palo Verde Nuclear Generating Station to become uneconomic earlier than planned, around the 2029 time period, with closure being a likely outcome.

In addition to renewables, the ballot initiative portfolio in the study was assumed to require utilities to invest in new generation capacity, including natural gas, to firm up the intermittent renewables. This is due to significant coal and nuclear resource retirements and load growth forecasts.

The assumptions used in the analysis are based on circumstances as they were on June 1, 2018.

Arizona’s Future Electricity Resources:

An assessment of the impact to Arizona electricity customers of the 50% Renewable Energy Ballot Initiative

Data and assumptions as of June 2018

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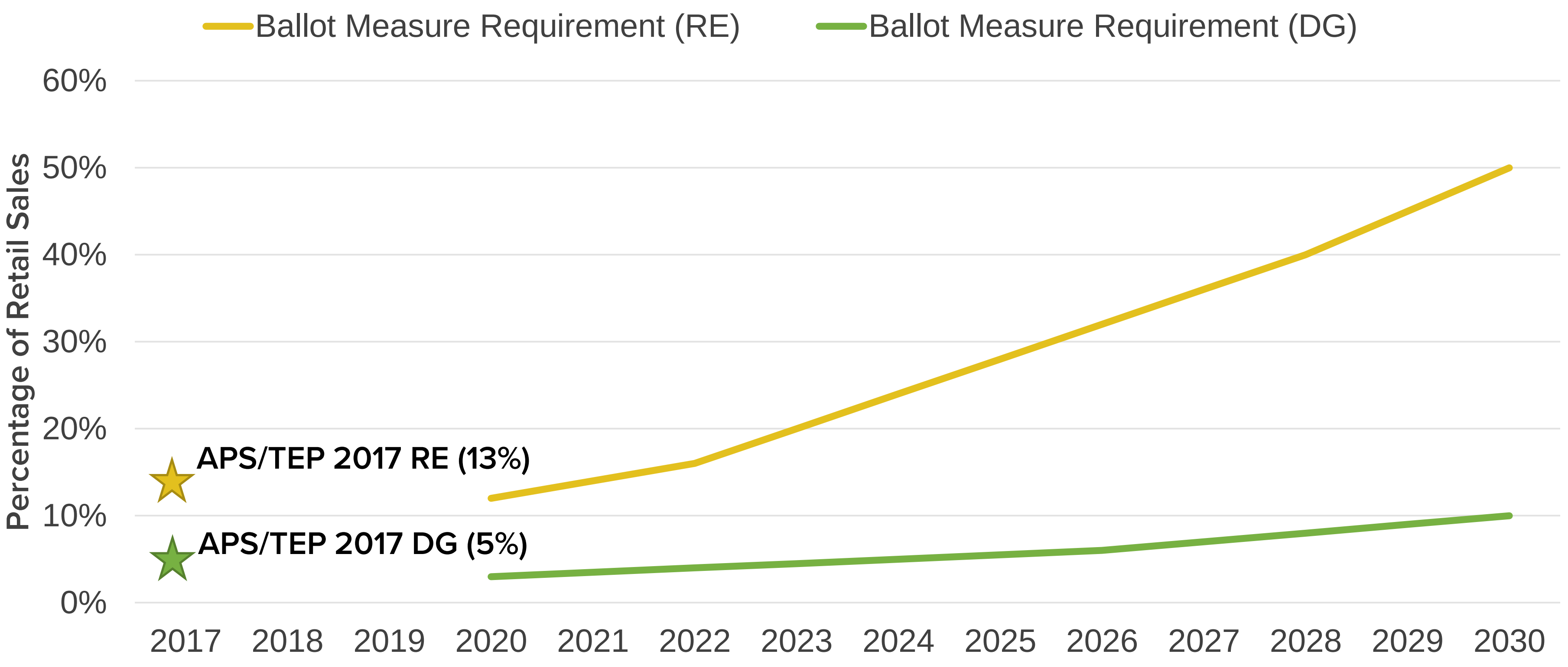
50% RE by 2030

50% RE by 2030 Initiative Requirements

A ballot measure was proposed in February 2018 known as the *Clean Energy for a Healthy Arizona* initiative. This initiative would require Arizona's investor owned utilities (such as APS & TEP -- not including SRP) to achieve 50% renewable energy (RE) by the year 2030 as a percentage of retail sales. Additionally, energy from distributed generation (DG) such as rooftop solar must equal 10% of retail sales.



Overview of RUCO’s Assessment of 50% RE by 2030

Developing a Portfolio: The Arizona Residential Utility Consumer Office (RUCO) conducted an assessment of the impact the 50% by 2030 proposal would have on Arizona Public Service (APS) and Tucson Electric Power (TEP) customers. To do this, RUCO developed a hypothetical energy resource portfolio that would meet the 50% requirements and compared this to a reference case or “business as usual” portfolio. For the reference case, RUCO used APS’ and TEP’s preferred 15-year resource plan, which each company developed through the Arizona Corporation Commission’s 2017 Integrated Resource Planning process.

The 50% portfolio was examined to ensure that sufficient resources were included to meet overall energy needs in each year (MWh). It was also examined to ensure that sufficient capacity was online to meet peak demand (MW) in each year, including a reserve margin. RUCO relied on APS’ and TEP’s forecasts of future growth in energy and peak demand.

The analysis was conducted using a simple spreadsheet based modeling tool. A more detailed analysis through the use of power system modeling tools (e.g. capacity expansion and/or production cost simulations) may provide more accurate assessment but was not possible due to time and budget constraints.

Comparing Costs: The overall cost to APS & TEP customers of the 50% portfolio was compared to the reference case. Portfolio costs were compared in terms of the net present value (NPV) of the annual revenue requirement from 2017 through 2032. This difference reflects the increase in costs due to additional new investments in generation resources and other necessary grid assets. It also reflects some reductions in costs due to decreased fuel consumption and O&M costs. These figures were used to estimate the overall impact to customer electricity bills. Additionally, RUCO examined the future economic viability of certain existing resources on the system, such as APS’ share of the Palo Verde Nuclear Generating Station.

Assumptions: As with any forward looking analysis of the electricity system, there are many underlying assumptions that influence the results. Many of the key assumption are detailed in an appendix to this report. While RUCO believes the analysis presented here is indicative of what may occur, many factors have substantial uncertainties that could change the outcome such as future wholesale market prices, future natural gas commodity prices, future cost of renewable energy and battery storage technologies, and future DG adoption rates.

Key Findings: APS, 50% RE

Assumed Resource Additions & Retirements - APS

Additional renewable energy resources were added to meet the 50% by 2030 requirements. This includes 3,000 MW of large scale solar PV and 1,400 MW of wind.

Recent reforms to retail rates have been adopted since APS' 2017 plan was developed. As such, RUCO assumed a slower pace of DG adoption than in APS' plan, but sufficient enough to meet the 10% requirement.

Some new natural gas combined cycle resources were deferred, but substantial additions of simple cycle combustion turbines (peaking units) and one new combined cycle plant were still necessary to meet peak demand. This is due to the limited capacity value assumed for solar PV at higher penetration levels. One NGCC tolling agreement that is in place today (but was not in identified in the reference case) was extended.

At higher RE penetration levels, renewable energy available during some hours could not be fully delivered due to overgeneration conditions and must be stored, exported, or curtailed.[1] Energy storage resources were found to limit curtailment by absorbing renewable energy during overgeneration conditions and delivering it later. Thus 860 MW of energy storage resources were added as a means to help meet the 50% requirement, as well as contribute to peak capacity needs.

Additional resource retirements were also assumed in the 50% case. APS' share of the Four Corners coal plant was assumed to be retired (or sold) at the end of 2025. APS' share of the Palo Verde Nuclear plant was assumed to be retired (or sold) at the end of 2029.

Each portfolio was determined to meet overall energy and capacity needs on an annual basis through 2032.

Resource Changes by 2030 (MW, nameplate)	APS 2017 Plan (Reference Case)	50% RE by 2030 Portfolio
Additions		
Natural Gas	+5100	+5690
Combined Cycle (incl. tolling)	*+2000*	*+1280*
Combustion Turbine	*+3100*	*+4410*
Solar PV	+2800	+5100
Solar PV (large scale SAT)	*+0*	*+3000*
Solar PV (distributed)	*+2800*	*+2100*
Wind	+0	+1400
Energy Storage	+500	+1360
Retirements		
Coal	-702	-1672
Navajo	*-315*	*-315*
Cholla	*-387*	*-387*
Four Corners	*-0*	*-970*
Nuclear (Palo Verde)	-0	-1146

[1] : Note that a truly accurate assessment of power system operations and associated costs under a 50% scenario (including the level of curtailment, exports, economic dispatch of existing generators, etc.) requires regional production cost modeling that was beyond the scope of this analysis.

Summary of Energy Mix - APS

Resource additions, retirements and capacity factors were initially based on the reference case.

Adjustments were made to resource addition/retirement schedule meet compliance with policy goals while ensuring capacity and energy needs are met.

Thermal plant capacity factors were adjusted as needed in each year to meet any incremental energy needs or capture potential fuel and O&M savings.

The total renewable energy (minus curtailments) was found to meet the 50% RE requirement and 10% DG requirement.

Energy Source (GWh)	APS 2017 Plan (Reference Case), 2030[3]	50% RE by 2030 Portfolio
Solar	7,018	14,052
Solar PV + CSP (large scale)	*1,758*	*10,120*
Solar PV (distributed)[1]	*5,260*	*3,932*
Wind	759	6,072
RE Curtailment	*(68)*	*(1,614)*
Coal	5,366	0
Natural Gas	17,105	16,306
Nuclear	9,287	0
Market Purchases	3,783	8,738
Retail Sales	35,360	36,825
Total RE[2]	7,730	18,510
RE % of retail sales (incl. DG)[2]	22%	50%
DG % of retail sales[2]	15%	11%

[1]: Distributed PV does not include pre-2019 non-incentive resources. Actual DG will be higher.
[2]: Total RE/DG GWh and %'s reflect reductions due to curtailment. DG was not assumed to be curtailable. Does not include pre-2019 non-incentive DG resources.
[3]: Resource outputs for Reference Case were estimated based on information in APS' plan. Some smaller resource contributions are omitted.

50% RE Portfolio Cost Comparison - APS

Estimates were developed for the incremental costs (or savings) for different elements of the 50% RE portfolio. These were then added to (or subtracted from) the reference case to determine a total difference in cost.

Each cost category is defined below:

- Incremental RE Resource Costs: cost of new renewable energy resources that are incremental to the reference case.
- Incremental Transmission Costs: cost of new transmission assets or wheeling charges necessary to deliver renewable energy resources. These are primarily driven by the cost of delivering wind resources from New Mexico.
- Incremental RE Integration Costs: additional costs of operating the power system to accommodate variable resources (i.e. wind and solar)
- Incremental ES Resource Costs: cost of energy storage systems that are incremental to the reference case
- DG incentive costs: cost of incentives to DG customers necessary to meet the 10% DG target provision of the initiative
- Avoided new natural gas costs: reduction in costs due to displacement of some new natural gas additions included in the reference case
- Additional fuel savings: reduction in fuel and O&M costs from existing coal, nuclear, and natural gas plant fuel costs due to displacement by renewables.
- Additional market purchases: cost of additional energy purchased from the wholesale market (net of any exports)

In addition to the direct costs identified, there is an opportunity cost due to the fact that renewables must be delivered to meet the 50% requirement at times that they could be curtailed to take negative market pricing. RUCO estimates this opportunity cost to be approximately $560 M NPV.

50% RE Portfolio Cost Estimates	Revenue Requirement, $M (NPV, 2017-2032)[1]	% Dif.
APS 2017 Plan (Reference Case)	**$25,951**	--
Changes Relative to Reference Case		
Incremental RE Resource Costs	$1,351	5.2%
Incremental Transmission Costs	$597	2.3%
Incremental RE Integration Costs	$529	2.0%
Incremental ES Resource Costs	$1,217	4.7%
DG Incentive Costs	$434	1.7%
Avoided New Natural Gas Costs (incl. fuel)	($463)	-1.8%
Additional Fuel & OM Savings	($838)	-3.2%
Additional Market Purchases (net of exports)	$21	0.1%
50% RE by 2030 Total Change	$2,848	11.0%

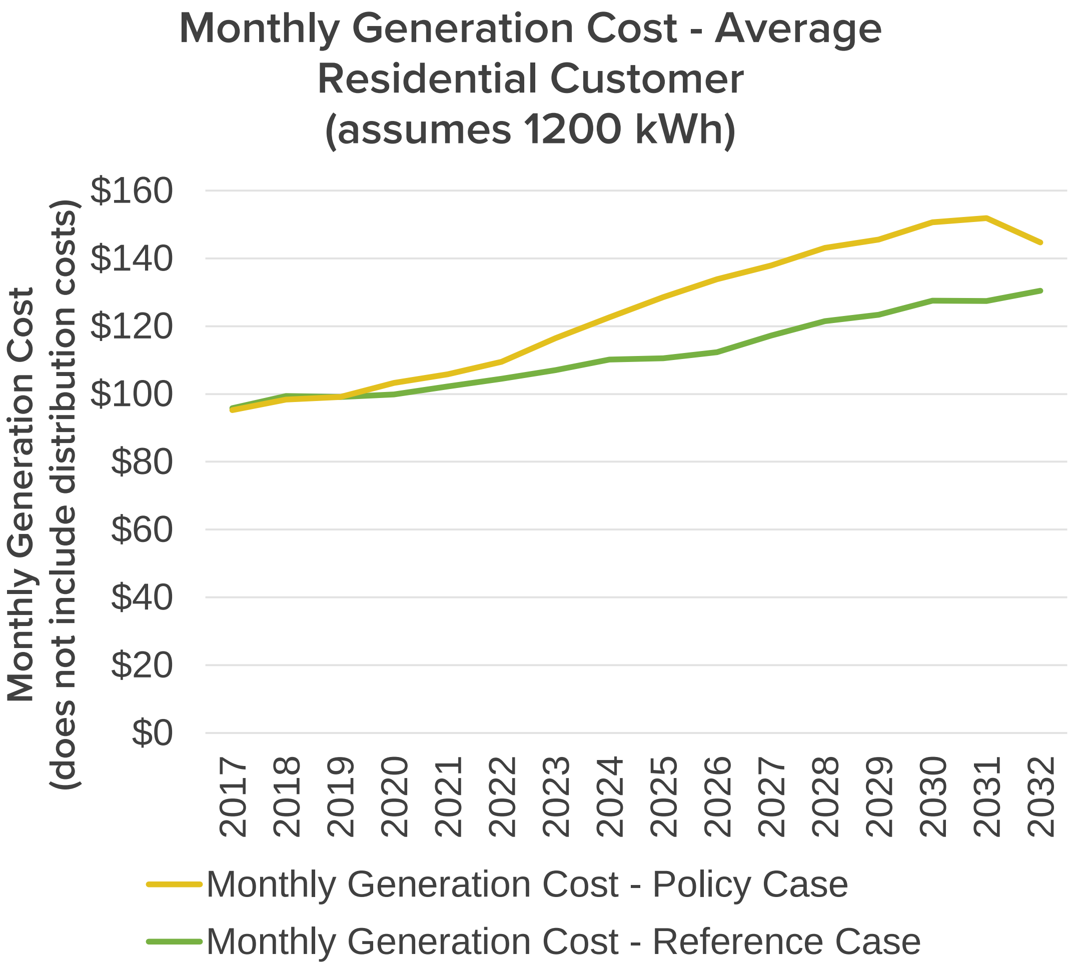
[1]: Assumes a discount rate of 7.5%. Revenue requirements reflects generation costs only (distribution costs are not included). 50% RE analysis does not reflect ability to bank RE credits, which may lead to reduced costs in some years.

50% RE Portfolio Bill Impact Analysis - APS

A customer bill impact analysis was performed for the 50% RE Portfolio. This reflects the potential change in the generation portion of a customer's bill. Note that this does not include distribution costs which represent an additional component of customer bills. For APS, it was assumed that a typical residential customer consumes 1,200 kWh per month in every year.

From 2017 to 2030, RUCO estimates that a typical residential customer's bill will increase by at least $630 a year ($53 per month) under the 50% RE Portfolio. For comparison, under the reference case, a customer's bill would increase by about $381 per year ($32 per month) over the same time period.

The cost of the 50% RE Portfolio decreases in the final year primarily due to the expiration of the Four Corners coal contract, allowing for additional fuel savings.



Palo Verde Nuclear Generating Station

In recent years, wholesale market power prices have been relatively low, primarily due to low natural gas commodity prices. Increased penetrations of renewable energy in the region (primarily driven by California) have placed further downward pressure on wholesale market prices though to a lesser degree than gas prices. This downward pressure is expected to continue as California achieves its 50% RE by 2030 requirement. Countervailing factors could include deployment of energy storage and electric vehicles.

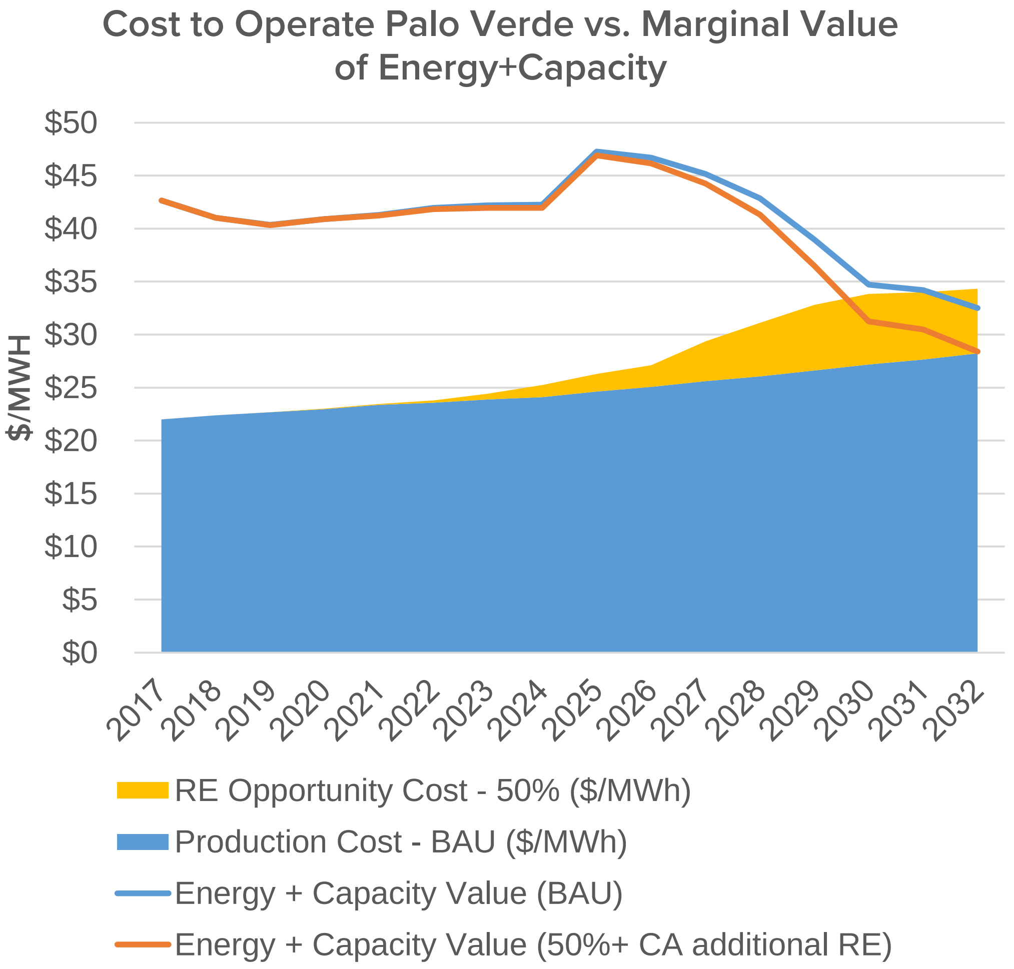
If market prices continue to remain flat or decline, there may be a point at which it is more economic to purchase wholesale power than to continue operation of an existing power plant. RUCO performed a preliminary assessment of the future economic viability of APS' share of the Palo Verde Nuclear Generating Station. This analysis was based on estimated plant operating costs and future wholesale market price forecasts.

Palo Verde's operating license currently extends into the 2040s. However, under a "business as usual" scenario, RUCO projects that the plant may become uneconomic in the mid 2030s due to declining wholesale market prices and increase plant operating costs. Under a scenario in which Arizona pursues 50% RE, RUCO estimates that this date would be accelerated.

Thus, in analyzing the 50% RE portfolio, RUCO assumed that APS' share of Palo Verde would be retired (or sold) at the end of 2029.

If Palo Verde remains online under a 50% RE scenario, there are likely to be more instances of "overgeneration" conditions during which excess renewable energy must be stored, exported, or curtailed. This is due to the fact that the plant cannot easily ramp down to take advantage of an increase in wind or solar production. As a result, excess RE must be procured to meet the 50% target to make up for any curtailment during overgeneration. This can be considered an additional "opportunity cost" of keeping the plant online under a 50% scenario.

Additional renewable energy deployed to meet a 50% AZ target does impact the plant's economic viability, but there are also other major factors impacting viability, such as low natural gas prices, California renewables, and rising plant operating costs.



Key Findings: TEP, 50% RE

Assumed Resource Additions & Retirements - TEP

TEP's 2017 Reference Case plan includes renewable resource additions over the next several years totaling about 325 MW of new wind and 450 MW of new solar PV. Additional renewable energy resources would be needed to meet the 50% by 2030 requirements for TEP. RUCO estimates that this could include 300 MW of additional wind, 100 MW of additional large-scale solar PV, and 470 MW of additional distributed solar PV.

In addition to renewable resources, incremental RICE unit additions were assumed to be needed to meet peak demand in later years as coal resources retire.

At higher RE penetration levels, renewable energy available during some hours could not be fully delivered due to overgeneration conditions and must be stored, exported, or curtailed.[1] Energy storage resources were found to limit curtailment by absorbing renewable energy during overgeneration conditions and delivering it later. Thus 110 MW of incremental energy storage resources were added as a means to help meet the 50% requirement, as well as contribute to peak capacity and integration needs.

Additional resource retirements were also assumed in the 50% case. TEP's share of one unit at Springerville generating station was assumed to be retired (or sold) at the end of 2027. While TEP's Reference Case assumes Four Corners retires after 2030, this retirement was accelerated by several years in the 50% case.

Each portfolio was determined to meet overall energy and capacity needs on an annual basis through 2032.

Resource Changes by 2030 (MW, nameplate)	TEP 2017 Plan (Reference Case)	50% RE by 2030 Portfolio
Additions		
Natural Gas	+604	+748
Combined Cycle	*+412*	*+412*
RICE	*+192*	*+336*
Solar PV	+680	+1020
Solar PV (large scale SAT)	*+450*	*+550*
Solar PV (distributed)	*+130*	*+570*
Wind	+325	+625
Energy Storage	+120	+330
Retirements		
Coal	-618	-1005
Navajo	*-168*	*-168*
San Juan	*-340*	*-340*
Four Corners	*-110*	*-110*
Springerville	*-0*	*-387*

[1]: Note that a truly accurate assessment of power system operations under a 50% scenario (including the level of curtailment, exports, economic dispatch of existing generators, etc.) requires regional production cost modeling that was beyond the scope of this analysis.

Summary of Energy Mix - TEP

Resource additions, retirements and capacity factors were initially based on the reference case.

Adjustments were made to resource addition/retirement schedule meet compliance with policy goals while ensuring capacity and energy needs are met.

Thermal plant capacity factors were adjusted as needed in each year to meet any incremental energy needs or capture potential fuel and O&M savings.

The total renewable energy (minus curtailments) was found to meet the 50% RE requirement and 10% DG requirement.

Energy Source (GWh)	TEP 2017 Plan (Reference Case), 2030[3]	50% RE by 2030 Portfolio
Solar	2,307	3,154
Solar PV + CSP (large scale)	*1,873*	*2,152*
*Solar PV (distributed)**	*434*	*1,002*
Wind	1,495	2,678
RE Curtailment	*-340*	*-720*
Coal	6,479	2,950
Natural Gas	4,322	6,059
Retail Sales	10,916	10,154
Total RE**	3,463	5,112
RE % of retail sales (incl. DG)**	32%	50%
DG % of retail sales	4%	10%

[1]: Distributed PV does not include pre-2019 non-incentive resources. Actual DG will be higher.
[2]: Total RE/DG GWh and %'s reflect reductions due to curtailment. DG was not assumed to be curtailable. Does not include pre-2019 non-incentive DG resources.
[3]: Resource outputs for Reference Case were estimated based on information in TEP's plan and some smaller resource contributions are omitted.

50% RE Portfolio Cost Comparison - TEP

Estimates were developed for the incremental costs (or savings) for different elements of the 50% RE portfolio. These were then added to (or subtracted from) the reference case to determine a total difference in cost.

Each cost category is defined below:

- Incremental RE Resource Costs: cost of new renewable energy resources that are incremental to the reference case.
- Incremental Transmission Costs: cost of new transmission assets necessary to deliver renewable energy resources. These are primarily driven by the cost of delivering wind resources from New Mexico.
- Incremental RE Integration Costs: additional costs of operating the power system to accommodate variable resources (i.e. wind and solar)
- Incremental ES Resource Costs: cost of energy storage systems that are incremental to the reference case
- DG incentive costs: cost of incentives to DG customers necessary to meet the 10% DG target provision of the initiative
- Avoided new natural gas costs: reduction in costs due to displacement of some new natural gas additions included in the reference case
- Accelerated cost recovery: increase in NPV costs due to accelerated cost recovery associated with early resource retirements at Springerville Unit 1 and Four Corners.
- Additional fuel savings: reduction in fuel and O&M costs from existing coal, nuclear, and natural gas plant fuel costs due to displacement by renewables.
- Additional market purchases: cost of additional energy purchased from the wholesale market (net of any exports)

In addition to the direct costs identified, there is an opportunity cost due to the fact that renewables must be delivered to meet the 50% requirement at times that they could be curtailed to take negative market pricing. RUCO estimates this opportunity cost to be approximately $136 M NPV.

50% RE Portfolio Cost Estimates	Revenue Requirement, $M (NPV, 2017-2032)*	% Dif.
TEP 2017 Plan (Reference Case)	**$9,683**	--
Changes Relative to Reference Case		
Incremental RE Resource Costs	$114	1.2%
Incremental Transmission Costs	$285	2.9%
Incremental RE Integration Costs	$25	0.3%
Incremental ES Resource Costs	$224	2.3%
DG Incentive Costs	$114	1.2%
Avoided New Natural Gas Costs (incl. fuel)	$141	1.5%
Accelerated Cost Recovery	$94	1.0%
Additional Fuel & OM Savings	($342)	-3.5%
Additional Market Purchases (or exports)	($168)	-1.7%
50% RE by 2030 Total Change	$490	5.1%

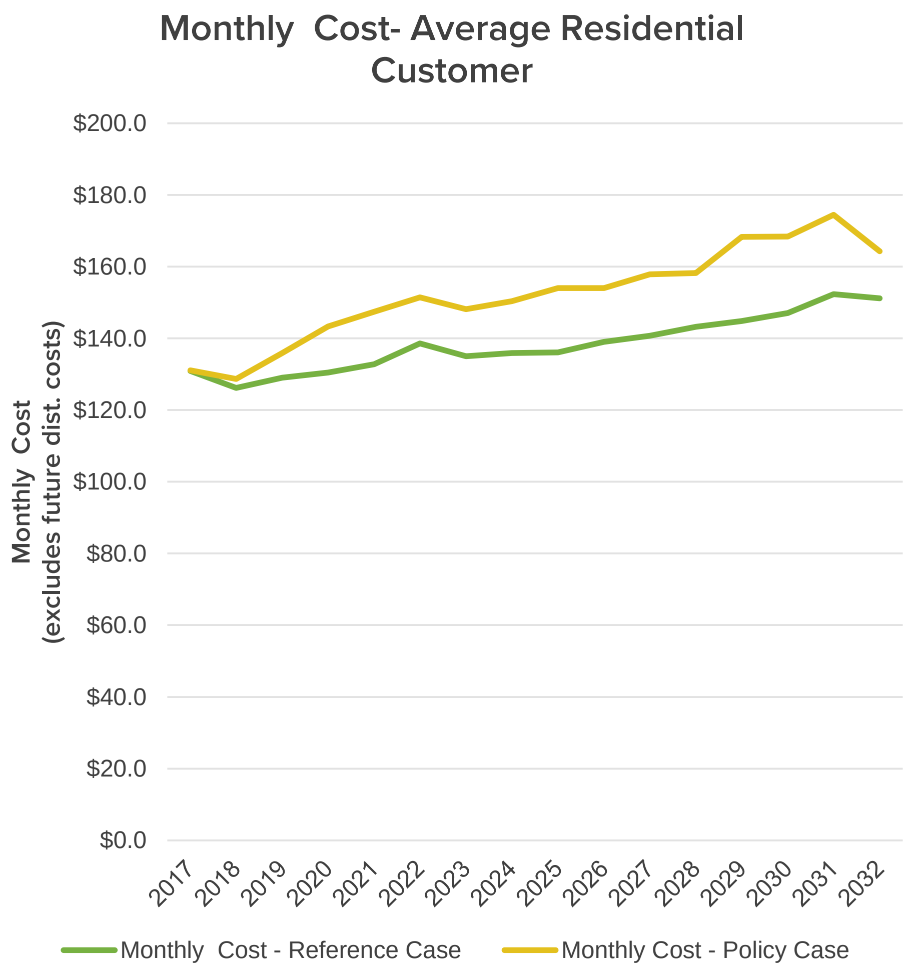
*Assumes a discount rate of 6.1%. Revenue requirements reflects generation costs only (existing transmission and distribution costs are not included). 50%

50% RE Portfolio Bill Impact Analysis - TEP

A customer bill impact analysis was performed for the 50% RE Portfolio. This reflects the potential change in the generation portion of a customer's bill. Note that this excludes future incremental distribution costs which would increase bills in both the 50% and reference case. This assumes that a typical residential customer consumes approximately 950 kWh per month in 2017, and that this would increase by approximately 0.7%/year.

From 2017 to 2030, RUCO estimates that a typical residential customer's bill may increase by approximately $449 a year ($37 per month) under the RE Portfolio. Under the reference case, a customer's bill would increase by about $193 per year ($16 per month) over the same time period.

The cost of the 50% Scenario decreases in the final year primarily due to the expiration of the Four Corners coal contract.

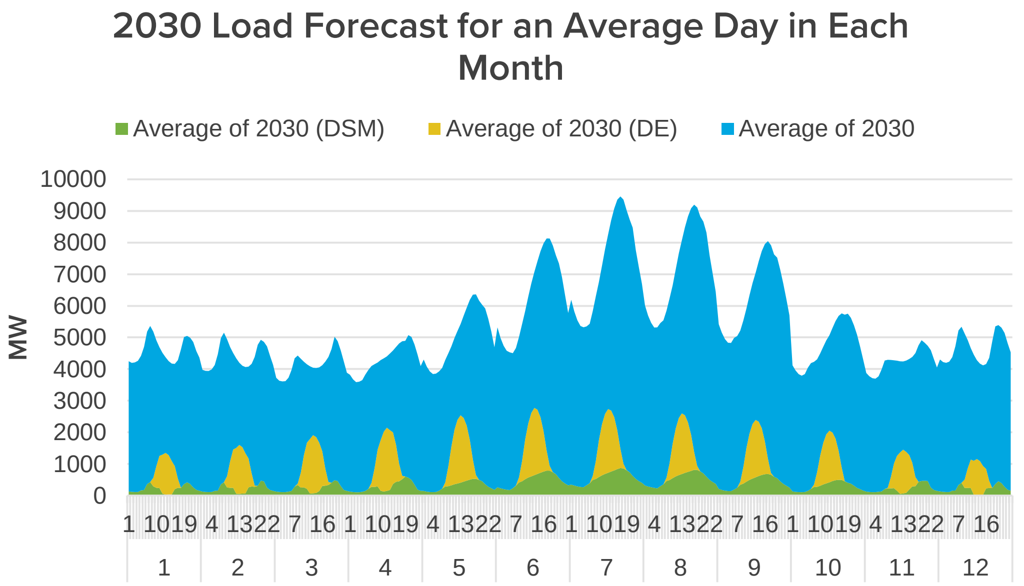


Key Assumptions

Load Forecast Assumptions - APS

A forecast of hourly load was provided by APS for each year through 2032. This forecast included the hourly load prior to the effects of incremental DG and Demand Side Management (DSM, e.g. energy efficiency). The forecast includes existing DG (approximately 600 MW) and DSM deployed in prior years. The hourly effects of incremental new DG and DSM were also provided by APS and were adjusted according to each scenario. No additional DSM was assumed beyond APS' Base Case.

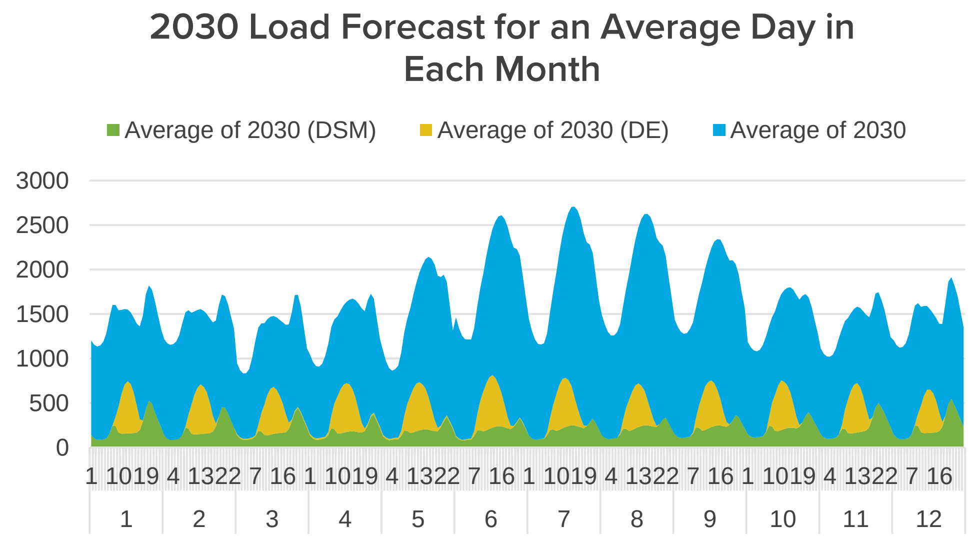
Portfolio	Load Prior to DG/DSM	DG, MWh in 2030	DSM, MWh in 2030
APS 2017 IRP	APS Forecast	APS Forecast	Base DSM Case
50% RE by 2030	APS Forecast	70% of APS Forecast	Base DSM Case



Load Forecast Assumptions - TEP

A forecast of hourly load was provided by TEP for each year through 2032. This forecast included the hourly load prior to the effects of incremental DG and Demand Side Management (DSM, e.g. energy efficiency). The hourly effects of both existing and incremental new DG and DSM were also provided. RUCO determined that ~2.4 times the amount of incremental annual DG included in TEP's initial forecast was needed to meet the 10% requirement under the ballot initiative. For the 50% RE case, the Base DSM Case was assumed.

Portfolio	Load Prior to DG/DSM	DG, MWh in 2030	DSM, MWh in 2030
TEP 2017 IRP	TEP Forecast	TEP Forecast	Base DSM Case
50% RE by 2030	TEP Forecast	~2.4 times TEP Forecast	Base DSM Case



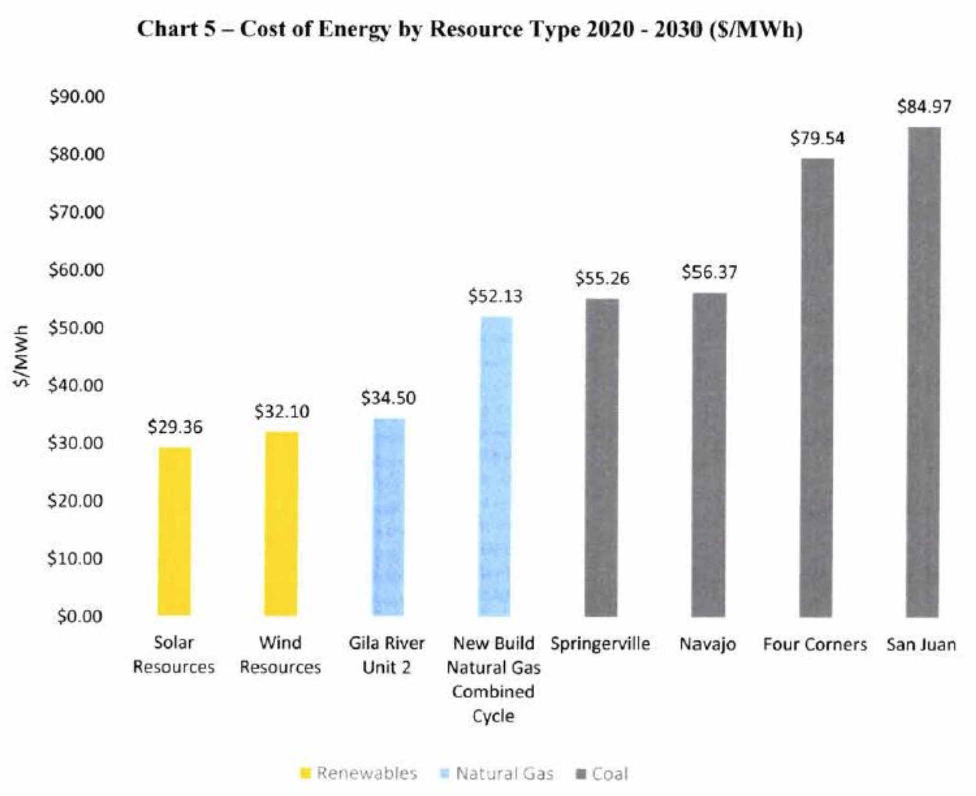
New Energy Resource Costs

New resource additions consisted primarily of solar PV, wind, and natural gas combustion turbines. Solar PV resources were assumed to be located in Arizona. Wind resource additions were assumed to be located in New Mexico which has higher quality wind resources. Solar resources were assumed to be comprised of 50% power purchase agreements (PPAs) and 50% utility owned systems. All wind resources were assumed to be PPAs.

RUCO estimates new PPA costs for solar PV to be approximately $30/MWh in 2020 and for wind to be approximately $28/MWh. These costs are consistent with those publicly reported for recent solicitations in the region. Renewable technology costs were anticipated to decline modestly over time (1%/yr for wind, and 2%/yr for solar PV). These declines are were offset by expiration of federal tax incentives (PTC/ITC) over the next several years, with corresponding adjustments made to resources costs in future years.

For APS, contribution to peak load (i.e. capacity value) from solar PV is expected to decline substantially as penetration increases. As such, new gas resources (primarily combustion turbines) were added to account for remaining capacity resource needs. Of these, approximately 1,100 MW were assumed to be aeroderivative type units (e.g. LMS100) and the remainder were frame type units (e.g. 7FA). Cost assumptions for these new gas resources were based on those included in APS' 2017 IRP.

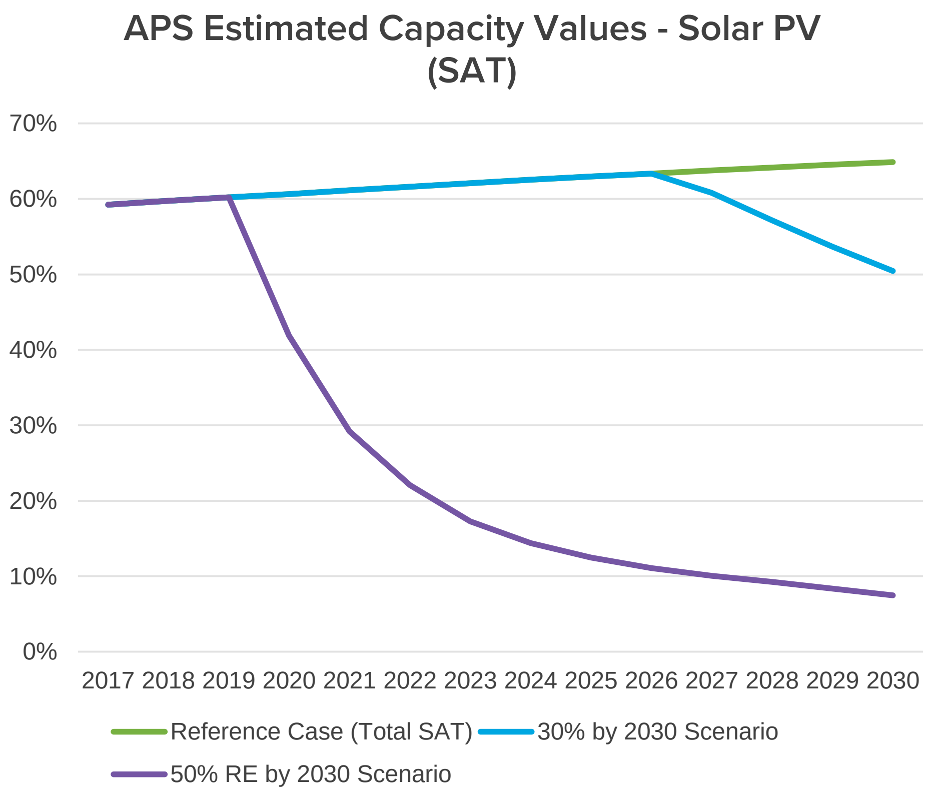
For TEP, natural gas RICE units were used to meet incremental capacity needs. Cost assumptions for these resources were based on those included in TEP's 2017 IRP.



Source: Tucson Electric Power
http://images.edocket.azcc.gov/docketpdf/0000187768.pdf

Solar PV Capacity Value

- RUCO relied upon estimates from APS of the capacity value of solar under a 50% portfolio expansion.[1]
- According to APS, under a 50% RE scenario similar to RUCO's, the capacity value for the total solar PV single-axis tracking fleet declines from 60% to 7% by 2030.
- For TEP's, meeting peak demand is not considered to be an important near term issue for system planning since there are sufficient resources for the foreseeable future. As such, a similar decline in capacity value for solar PV was not studied or considered for TEP's system.



[1]: Methods used to study and assign capacity values to different resources can vary substantially. APS' methodology for determining solar PV capacity value was described to RUCO as an "Effective Load Carrying Capability" (ELCC) approach. Potential synergies could exist between different resource types, but such an assessment was beyond the scope of this analysis. Further study of capacity values of under different resource mixes is recommended.

Transmission

Renewable resource additions were limited in some years to account for transmission availability.

Additional transmission upgrades were assumed for APS near the Palo Verde hub to increase solar PV import capability to the Phoenix load area in 2021, 2027 and 2029. Each upgrade was assumed to cost $100 M (based on an estimate provided to RUCO by APS) in 2017 dollars and would increase transfer capability by approximately 900 MW. For comparison, APS' 2017 Plan estimates that $200M of transmission upgrades would be needed to accommodate 3500 MW of new natural gas resources.

Wind resource additions were timed to leverage existing transmission capability made available due to coal retirements. Additional wheeling costs were assumed to deliver wind resources from wind-rich areas in NM. According to TEP, the range of transmission wheeling costs in the region can be reasonably approximated to be $1.50-3.00/kW-mo (per wheel). Based on this, we assumed all wind resource additions assumed to include a $9-10/MWh transmission cost adder in the early years, reflecting the wheeling cost for transporting wind resources from New Mexico to the APS/TEP systems. This is consistent with estimated hurdle rates (including wheeling) that others have estimated for utilities in the region.[1] The adder was assumed to increase to $22/MWh in later years, reflecting the incremental cost of new transmission additions consistent with the methodology used in a recent study conducted by NREL and Bureau of Reclamation on the feasibility of use renewable energy as a replacement resource for Navajo Generating Station.[2]

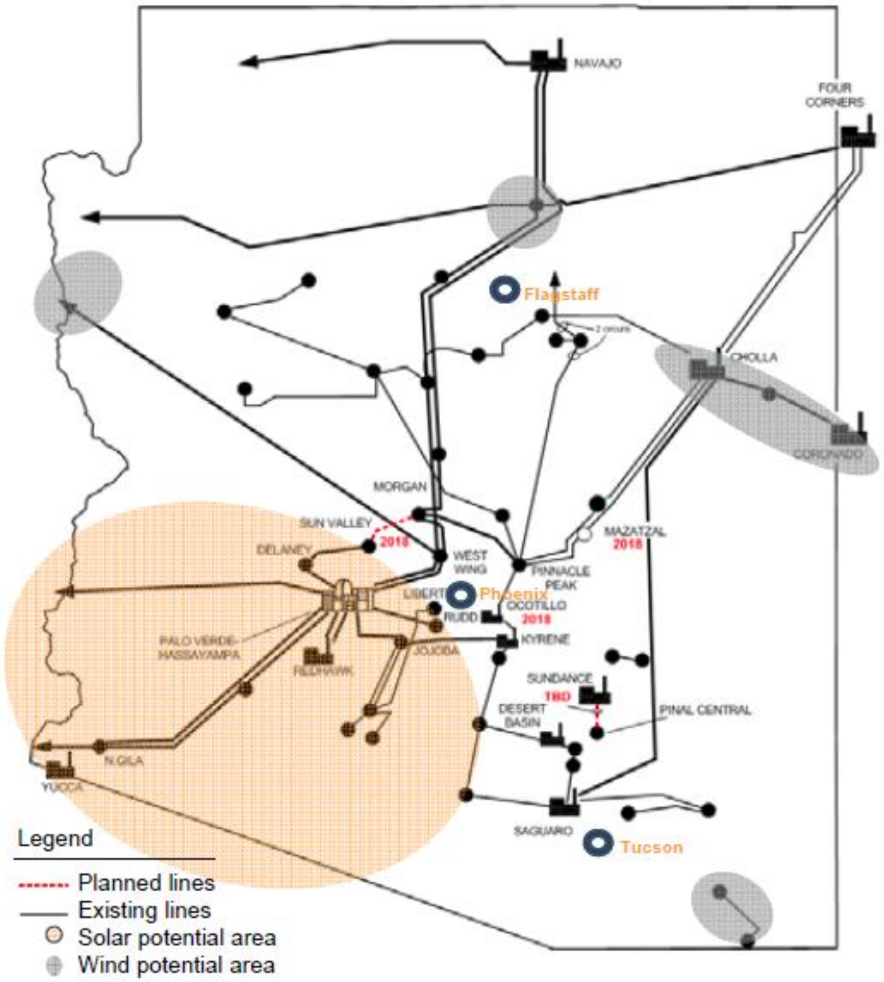
According to APS, the only viable way for wind energy from NM to ultimately reach the Phoenix load area would be to go through the Four Corners location. APS planners informed RUCO that it would be exceedingly difficult to find an alternative delivery route or to acquire transmission rights from another entity. The retirement of APS' 970 MW share of Four Corners was assumed to allow that amount of wind power to be delivered starting in 2026. Beyond this, according to APS, there is very limited transfer capability from Four Corners to other potential delivery points (e.g. Cholla and Moenkopi), necessitating the construction of new transmission upgrades or new lines. For APS' 50% portfolio, We assume an additional transmission line is built from Four Corners to Cholla to accommodate additional wind delivery starting around 2026 at a cost of $300M.

Additionally, we assume some very limited transmission availability to other delivery points in earlier years. For example, APS recently reported 451 MW of available transmission capability from Four Corners to Moenkopi and 1506 MW of available transmission capability from Saguaro to Cholla.[3] APS is also expected to complete transformer upgrades at Four Corners in 2018 that will impact the deliverability of power in the region. APS also recently completed a study indicating that additional transformer upgrades at Four Corners could increase transfer capability by 500 MW at a cost of $28M.[4]

Regardless of the policy scenario, RUCO recommends that further study on the AZ transmission system to identify the location and timing of the most cost-effective upgrades for delivering clean energy resources – particularly those aligned with peak needs.

[1]: For an example, see Figure 14, http://www.caiso.com/Documents/SB350Study-Volume5ProductionCostAnalysis.pdf
[2]: https://www.nrel.gov/docs/fy17osti/66506.pdf
[3]: https://doc.westconnect.com/Documents.aspx?NID=17941
[4]: http://www.oasis.oati.com/AZPS/AZPSdocs/FC_TSR_SIS_20180510.pdf
[5]: http://s22.q4cdn.com/464697698/files/doc_presentations/2018/Investor-Meetings-April-10-11-2018.pdf

APS Transmission System Map[5]



Distributed Generation

The 50% RE initiative requires utilities to obtain Distributed Renewable Energy Credits (D-RECs) from distributed renewable resources equal to 10% of their retail load. Under the existing 15% RES, transfer of Renewable Energy Credits (RECs) from DG owners to the utility was originally facilitated through the use of upfront incentives. Eventually these incentives fell to zero and, as a result, RECs were no longer transferred, but DG continues to be reported for informational purposes.

For existing DG that was incentivized in this manner, utilities already have the ability to claim these RECs and this portion is assumed to contribute to the 50% target. For existing DG that was not incentivized, no contribution was assumed.

There may be other means other than upfront incentives to facilitate transfer of D-RECs. However, for the purposes of this assessment, RUCO assumes that an upfront incentive would be needed. The assumed cost for purchasing D-RECs from distributed generation owners is $0.30/W in 2019. This incentive level was escalated by 5%/yr to account for a corresponding decrease in the assumed compensation rate (e.g. via the “RCP value”) in future years. No credits were assumed for new DG until 2019, or unincentivized DG from prior years.

Integration Costs

Integration costs arise from any incremental costs to operate the power system to accommodate for the variability and uncertainty of wind and solar resources. According to APS, integration costs on their system are primarily driven by an increased need to provide additional frequency regulation services at higher levels of RE penetration.

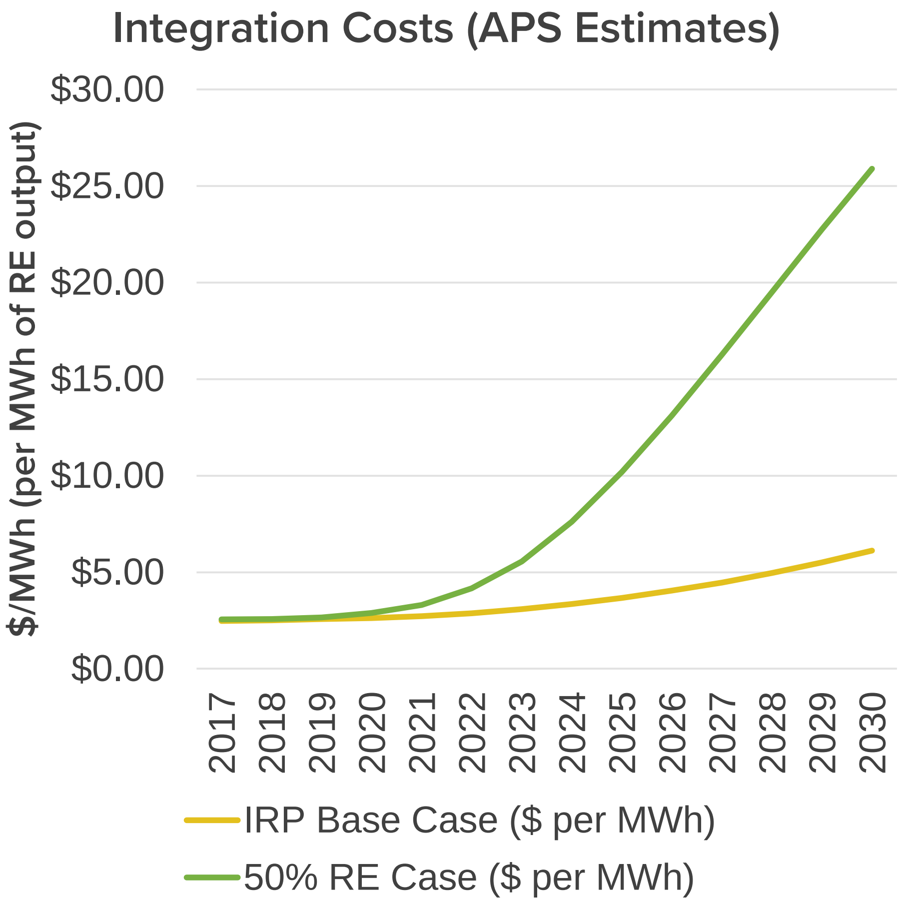
A previous study conducted by Argonne National Lab showed integration costs on the APS system for a 22% RE scenario to be in the $2-4/MWh range (per MWh of renewable energy generated). Incremental need for regulation service under a 50% scenario could put upward pressure on $/MWh integration costs.[1]

APS estimates integration costs in its reference case (2017 IRP) to increase from $2.47/MWh in 2017 to $6.11 per MWh of renewable energy generated in 2030. Under a 50% portfolio, APS estimates that integration costs would rise to $25.90 per MWh of RE generated in 2030. A detailed methodology on how these costs were determined was not provided. For comparison, a study of integration costs by Xcel Energy (a Colorado utility), showed integration costs of $4.09/MWh for a 43% RE scenario.[2]

RUCO's 50% by 2030 portfolio assumed an additional 860 MW of battery storage, which is an excellent provider of regulation service. As such, RUCO assumed integration costs between the range of estimates provided by APS when assessing the 50% RE case.

According to TEP, incremental integration costs are largely embedded in the cost of new balancing resources such as battery storage or RICE units, and any additional operating cost is likely to small.

RUCO believes further study may be needed to determine what integration costs would be under different high RE scenario. Going forward, integration costs could significantly change due to a variety of factors including: the mix of renewable and storage resources, load variability, potential use of advanced RE dispatch and controls, improvements to RE forecasting techniques, flexibility of the baseload fleet, geographic diversity of resource deployment, and joint operation/controls between utilities.



[1]: Argonne National Laboratory, "Integrating Solar PV in Utility System Operations" October 2013, http://www.ipd.anl.gov/anlpubs/2013/11/77596.pdf
[2]: Public Service Company of Colorado 2 GW and 3 GW Wind Integration Cost Study, August 2011, http://www.ccj-online.com/wp-content/uploads/2011/11/LINK-A-CCUG-11M-710E_2G-3GReport_Final.pdf

Energy Storage

Battery energy storage systems were deployed to provide system capacity, aid with renewable integration, and to avoid overgeneration during low load conditions.

Costs were based on Lazard's Levelized Cost of Storage for a peaker replacement use case.[1] Storage was assumed to be paired with renewable resources to leverage the federal investment tax credit. Installed costs were assumed to decrease by 3.5%/yr.

80% of Energy Storage resources were assumed to be utility owned and 20% contracted.

An arbitrage value was also assigned to storage based on the hourly market price forecast during charging and discharging. During overgeneration conditions, the charging cost was assumed to be zero.

Storage was modeled after a lithium-ion battery with a four hour duration and was assumed to have an 85% round trip efficiency.

Charging and discharging profiles were selected set to match peak and off peak loads for each month of the year.

[1]: Lazard Levelized Cost of Storage 3.0, Nov 2017, https://www.lazard.com/media/450338/lazard-levelized-cost-of-storage-version-30.pdf

Avoided Fuel Costs

Fuel and OM Savings

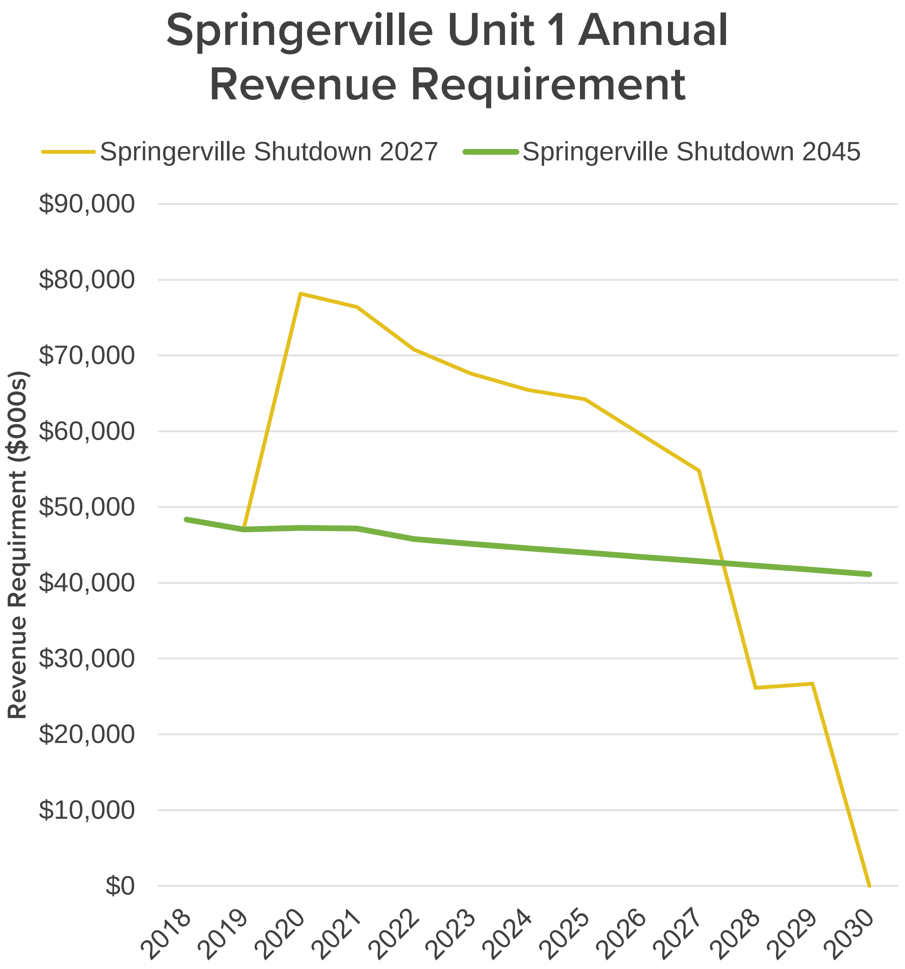
Adjustments to the capacity factors of existing coal and natural gas generation were made to ensure overall energy needs were met in each year. Increases or decreases in fuel and variable O&M costs were calculated accordingly, based on plant characteristics provided by APS and TEP (e.g. heat rate, variable O&M costs, etc). Additionally, fixed O&M savings were calculated for early plant retirements (i.e. Four Corners, Palo Verde, Springerville).

Must Take Coal Contracts

Several coal plants (e.g. Springerville, Cholla, Four Corners) have “must-take” provisions associated with their coal contracts. As such any fuel savings associated with reduced output at these plants would not be realized until after the contracts end in 2020 for Springerville, 2025 for Cholla and 2031 for Four Corners. While these contracts are confidential, it is RUCO’s understanding that no part of these contracts would allow the must take provisions to be renegotiated.

Accelerated Cost Recovery

- For TEP, early retirement of existing coal units was assumed to lead to accelerated cost recovery.
- Remaining book value for Springerville Unit and Four Corners (including SCR costs) was assumed to be recovered by 2027, with additional decommissioning costs in years 2028 and 2029.
- The difference in revenue requirement for each year through 2032 was calculated for each of these units, and the NPV of those differences was calculated.
- It is possible that the ACC could as a policy matter, allow costs to be recovered according to the original depreciation schedule if treated as a regulatory asset. In this case there would be no increase associated with accelerated cost recovery.
- A similar analysis was not performed for APS due to lack of information on accelerated depreciation schedules.



Market Price Forecasts

RUCO relied upon hourly Day Ahead market price forecasts for the Palo Verde hub provided by APS.

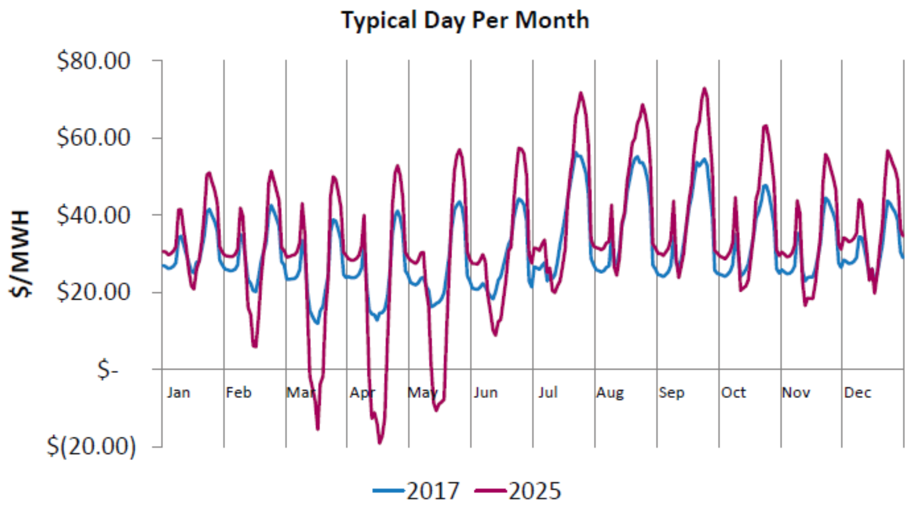
Average power prices have been low recently due to low natural gas prices. Low or negatively priced energy have appeared predominately in the 5-minute Real-Time market during low load conditions in the spring. In the Day Ahead market, negative pricing has been somewhat rare but have occurred on some occasions.

To date, the quantity of energy purchased at a negative price energy from the wholesale market has been limited. However, going forward, the frequency and magnitude of negative pricing events is likely to increase as renewable penetration increases. AZ is highly exposed to CA markets that drive this phenomenon.

There are a multitude of factors that could influence the accuracy of the future wholesale price forecasts in Arizona (including the prevalence of negative pricing) including:

- Natural gas commodity prices
- Natural gas pipeline availability
- Deployment of energy storage
- Changes to the transmission network
- Development of organized markets and market products
- Future precipitation in the Pacific NW (affecting hydro imports to CA)
- Retirement of older inflexible OTC steam generation units in CA
- Diversity of future RE deployment

FIGURE 7-3. PALO VERDE HUB MARKET PRICES



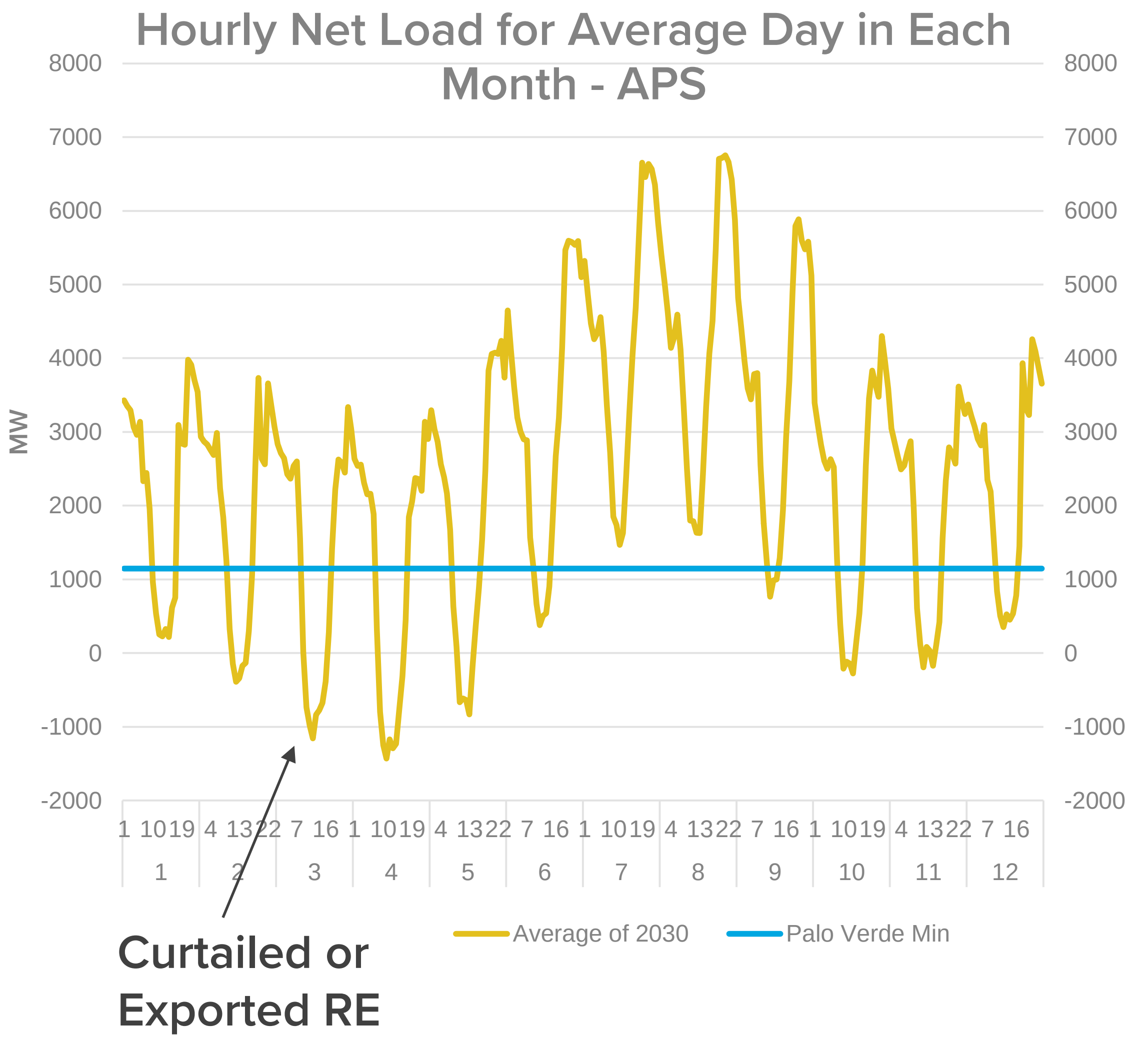
Overgeneration & Curtailment

Hourly load, RE production, and storage dispatch was used to determine overgeneration conditions. This occurs when available renewable energy output exceeds the system load after accounting for certain “must-run” generation units that can’t be ramped down. Must-run units were assumed to include Palo Verde, Four Corners, and some natural gas for regulation and spinning reserves.

Spinning reserve requirements were based on estimates provided by APS of 250 MW today, increasing to approximately 400 MW by 2030. For TEP this was assumed to be equal to the minimum generation of the Luna and Gila River 3 units.

During overgeneration conditions, excess energy was assumed to be exported (up to a 1,500 MW limit for APS and 500 MW for TEP) if the market price was positive. If the market price was negative, excess RE was curtailed.

Curtailment in 2030 of total RE available was expected to be approximately 10% for APS and 11% for TEP under the ballot initiative.



Palo Verde Cost and Value

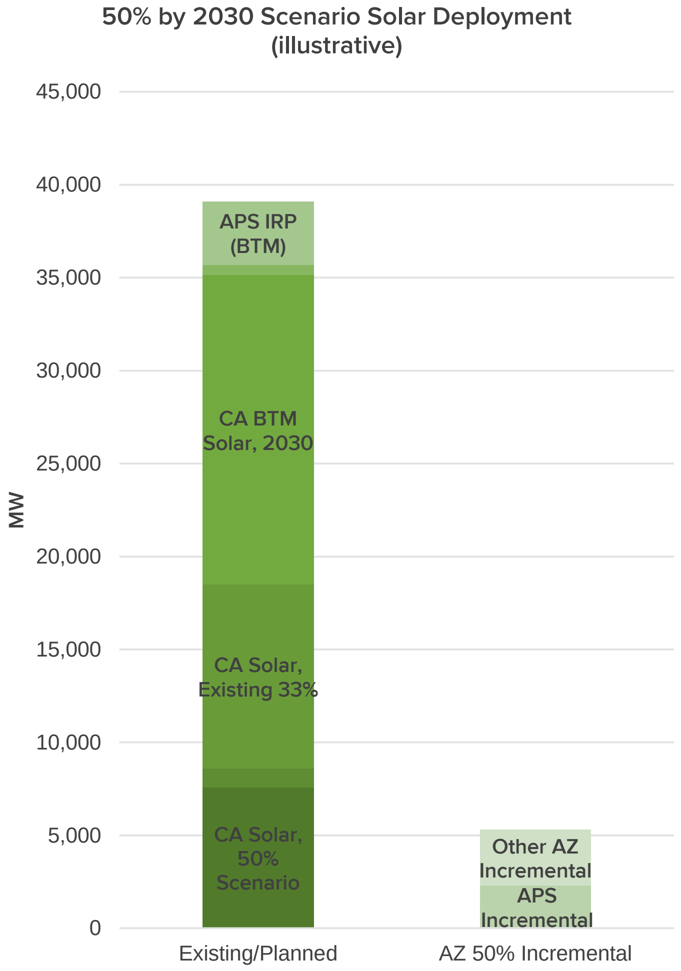
The value of energy from Palo Verde is assumed to equal the hourly DA market prices at Palo Verde hub (based on APS' forecast) when plant is operating. RUCO assumes the plant operates at a 98% capacity factor during most months, except during April and October when one unit is down for refueling. The annual capacity factor would be approximately 92%.

The value of capacity is assumed to equal the fixed cost of new GE 7F.05 Combustion Turbine (escalated at 2.5% annually), levelized over the annual production of the Palo Verde plant.

RUCO anticipates future price exposure at the Palo Verde hub will be dominated primarily by natural gas prices and secondarily by California markets and policies. Arizona policies will have a smaller but still meaningful impact. The chart on the right illustrates the potential incremental solar that might by deployed in Arizona under a 50% RE scenario versus the total existing and planned solar already anticipated for California and Arizona by 2030. The AZ 50% incremental solar resources were estimated account for about ~10% of the total existing/planned solar resources in Arizona and California combined. To evaluate a 50% by 2030 AZ scenario, negative pricing events were assumed to be amplified by 25% to account for the incremental impact AZ resources may have, as well as additional California renewables beyond 50%. Natural gas is expected to be the marginal resource during most other hours (when prices are positive) so additional AZ renewables were not assumed to have a significant effect.

Palo Verde total production costs (fuel plus O&M) were based on APS' estimate of $22/MWh in 2017. The fuel cost component was escalated according to projected valued in APS' IRP, and O&M cost were escalated at 2.5% annually.

RE Curtailment Opportunity Costs were included to reflect the incremental cost of renewable energy resources that must be procured to meet the 50% RE target if the plant is kept operational (due to curtailment). This incremental cost was assumed to include two components 1) the cost to procure the incremental renewable resources and 2) the inability to take negative pricing while those incremental RE resources are being curtailed during overgeneration conditions (net of any decreased export potential).



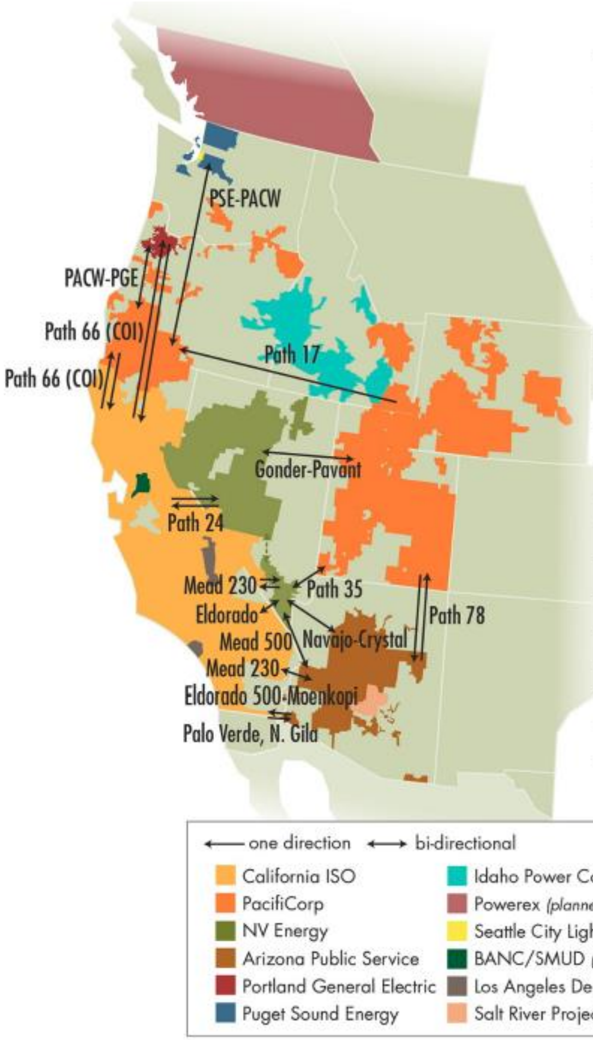
California solar resource estimates based on CAISO SB350 Study Analysis

Study Limitations

This analysis only considers each utility's balancing area in isolation.

In reality the grid is interconnected and there is power flow between balancing areas as illustrated by the map on the right.

Flow between areas could significantly alter unit commitment and economic dispatch, integration costs, transmission availability, avoided fuel costs, market purchases/sales, curtailment and overgeneration to be expected. However, a more detailed power flow and production cost simulation is needed to examine this.



Path	Estimated Max Capacity (MW)*
Path 24 *(west to east)*	100
Path 24 *(east to west)*	35-90
Eldorado	797
Path 35 *(west to east)*	580
Path 35 *(east to west)*	538
Gonder-Pavant	130
PACW to PGE	320
Path 66 *(ISO to PGE)*	627
Path 66 *(PGE to ISO)*	296
Path 66 *(ISO to PACW)*	331
Path 66 *(PACW to ISO)*	432
Path 17	400
PSE to PACW	300
Eldorado 500-Moenkopi	732
Palo Verde, N. Gila	3,151
Path 78 *(PACE to APS)*	625
Path 78 *(APS to PACE)*	660
Navajo-Crystal	522
Mead 500	349
Mead 230 *(APS <–> ISO)*	236
Mead 230 *(ISO to NVE)*	3,443
Mead 230 *(NVE to ISO)*	3,476

*Current as of December 2017

Graph 1: Estimated maximum transfer capacity (EIM entities operating in Q4 2017)