Arizona Coal Plant Valuation Study

STRATEGEN CONSULTING

Economic assessment of coal-burning power plants in Arizona and potential replacement options

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Executive Summary

Coal-burning generation serving Arizona customers is no longer economically competitive when compared to renewable energy resources such as wind and solar, or market purchases. Already, older coal-burning units powering the state have higher levelized costs of energy (LCOE) on a going forward basis than their replacement options. More specifically, retiring all 11 units at the six coal facilities examined in this study and replacing them with a solar PV plus storage or wind resource can save Arizona customers upwards of $3.5 billion.

Coal unit replacement with alternative resource options in the 2023 timeframe provides significant economic benefits to electricity consumers due to reduced operating and maintenance costs (including fuel) and avoided incremental capital costs, while at the same time dramatically reducing emissions. Among replacement options, solar generation plus storage is less expensive on a LCOE basis when compared to all the coal-burning units analyzed. Wind from New Mexico is also cheaper than the continuing operation of most of those units.

In addition to the operating and fuel savings that come from the replacement of coal-burning units with cleaner resources, there are also potential savings for ratepayers based on the regulatory treatment of the undepreciated value of the assets. An illustrative example of securitization in case of retirement of the first unit at Springerville shows significant additional savings on top of those achieved by the avoidance of its operating and fuel expenses.

The study also analyzed the Four Corners plant, one of the largest coal plants to service Arizona, and concluded that despite the coal supply agreement with the Navajo Transitional Energy Company through 2031, its continuing operation is more expensive than replacement options. The potential benefits from a Four Corners plant retirement, although significantly reduced by the plant's existing coal supply obligation, are still high enough to justify its replacement by other generation options in the near term.

1. Introduction

The U.S. coal-burning plant fleet is aging and facing increasing economic pressure due to the falling costs of renewable energy generation. Nationally, in 2018 and 2019, 100 units with a combined capacity 32,649 megawatts (MW) retired or are scheduled to retire. This trend has been particularly strong in the West and includes Arizona's Navajo Generating Station (NGS) -- the largest coal-fired power plant operating in the western U.S. -- which will close at the end of 2019. The transition away from coal increasingly makes economic sense due to reductions in the cost and the technology advancement of renewable energy and energy storage.

On behalf of the Sierra Club, Strategen conducted an economic analysis to better understand which of the coal units that serve Arizona's load may be most suitable for replacement with clean energy on an economic basis. The study concluded that all the coal units serving Arizona load are more expensive than currently available cleaner options. Arizona ratepayers stand to save money on their electricity bills by the retirement of coal-burning units and their replacement with renewable resources.

Recognizing the economic trend, Arizona Public Service (APS) has announced its plans to cease coal generation by 2038.[1] Similarly, Tri-state Generation and Transmission, a wholesale power supplier to western energy co-ops, has retired one coal-burning plant and plans to retire two more by the end of 2025, in addition to installing 100 MWs of solar and 104 MWs of wind in 2019[2]. Salt River Project (SRP) aims to reduce its coal fleet carbon emissions by 30% by 2035 and reduce its CO_2 emissions by 90% from 2005 levels by 2050[3]. Tucson Electric Power (TEP) plans to reduce reliance on coal to 38% of retail energy deliveries by 2030 and serve 30% of its retail load with renewable generation by 2030[4].

While there is a clear intention to move away from coal-burning generation, the pace is not fast enough to fully capture the economic benefits of this transition, and Arizona ratepayers might end up paying more than they should to keep expensive coal units operating for several more decades. Other western states are more ambitious in their plans to reduce coal-burning generation and increase renewables. For example, in spring 2019, Nevada passed a bill that would require the state to generate 50% of its electricity from renewable resources by 2030 and aim for 100% carbon-free resources by 2050. NV Energy supported the bill and has plans to add over 1.2 GW of solar and 590 MW of battery storage to its generation mix, pushing it past its target to double renewable energy capacity between 2018 and 2023.[5] Similarly, New Mexico has committed to 100% carbon-free electricity by 2045. The Public Service Company of New Mexico aims to

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[1] Arizona Public Service Integrated Resource Plan Stakeholder Meeting Presentation, April 4, 2019. Accessed at https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

[2] Tri-State Generation and Transmission, Responsible Energy Plan. Accessed at: https://www.tristategt.org/responsibleenergyplan

[3] Salt River Project, 2035 Sustainability Goals. Accessed at: https://www.srpnet.com/environment/sustainability/2035-goals.aspx

[4] Tuscon Electric Power, 2018 Action Plan Update. Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[5] See: https://www.greentechmedia.com/articles/read/nv-energy-signs-a-whopping-1-2-gigawatts-of-solar-and-590-megawatts-of-stor#gs.16tp1m

eliminate carbon emissions from its power generation by 2040.[6] The Colorado Energy Plan is Xcel Energy's roadmap to develop a significantly cleaner energy mix and reduce carbon emissions in Colorado aiming for nearly 55% renewable energy by 2026, and a 60% reduction of carbon emissions from 2005 levels.[7] Within this context, Arizona utilities could speed up the retirement of coal units and invest in renewable energy, all while achieving net savings for their ratepayers, as shown in the study.

On the policy front, the Arizona Corporation Commission (ACC) adopted a Renewable Energy Standard (RES) in 2006 that calls for 15% of Arizona's power fleet that is regulated by the ACC to be powered by renewables by 2025, and for 30% of that renewable energy to come from distributed energy technologies. The Commission is now considering whether to expand this standard to account for the increasingly favorable economics and customer preference for renewable energy infrastructure. For example, the Commission Staff recently put forward a proposal that includes a voluntary renewable energy goal of 45% by 2035.[8] In response, 25 stakeholders developed a joint proposal that includes enforceable standards for 100% clean energy by 2045 and 50% renewable energy by 2030, aligning Arizona's goals with those of other western states.[9]

As mentioned above SRP has committed to a significant carbon emissions reduction goal in addition to deploying over 1000 MW of solar energy resources by 2025.

Strategen conducted a discounted cash flow analysis examining a "business-as-usual" case of energy production at 11 coal-burning generation units serving Arizona electricity customers. This analysis estimated the levelized cost of energy (LCOE) and the net present value (NPV) of costs for each coal unit's operating, maintenance, and incremental capital costs. Strategen then compared those results with the economics of three replacement portfolios: solar photovoltaics (PV) paired with battery storage, wind, and market-purchased energy. The analysis relied on data from publicly available sources as well as S&P Global Market Intelligence (formerly SNL) to estimate the levelized costs of renewable energy and coal-burning power.

Additionally, the study calculated the societal benefits of coal retirements based on the assumed future carbon price included in Arizona Public Service's Integrated Resource Plan. The study also included the effects that the existing must-take coal contract for the Four Corners plant would have on an early retirement decision, and finally the economic impact of installing pollution control equipment in the second unit of Coronado. Finally, the study includes an illustrative example of the additional savings for ratepayers that a refinancing mechanism could bring about. Arizona's utilities can both save families money on their electricity bills and clear pollution out of our communities and national parks by quickly replacing all coal power with new renewable infrastructure to take advantage of the state's abundant solar resources.

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[6] See: https://www.utilitydive.com/news/pnm-avista-commit-to-carbon-free-goals-on-heels-of-state-mandates/553240/

[7] Colorado Energy Plan. Accessed at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/CO-Energy-Plan-Fact-Sheet.pdf

[8] See: https://docket.images.azcc.gov/0000198875.pdf

[9] See: https://docket.images.azcc.gov/E000002141.pdf

2. Arizona's Coal Fleet

2.1. Coal Fleet

Arizona hosts five coal-burning generation stations. Two of those plants, Navajo and Cholla, are scheduled to be retired in 2019 and 2025 respectively and were not examined in this study. The three remaining plants, with seven generating units, are scheduled to operate until 2035 or later were analyzed in this study. Additionally, Arizona draws power from four coal-burning generation units at three plants outside the state -- Craig, Four Corners, and Hayden -- which were also examined. Together, the 11 coal-burning units that this study analyzed have a combined operating capacity of 4,792 MWs. Seven of those 11 units are 39 years or older, with Four Corners Unit 5 being the oldest. Springerville's four units are newer, with the most recently constructed Unit 4 beginning operations in 2009. Owners of the coal units examined in this study include utilities serving Arizona customers such as Arizona Public Service, Tucson Electric Power, Salt River Project, and Arizona Electric Power Cooperative. Additionally, some of the plants are co-owned by non-Arizona utilities including PacifiCorp, Xcel Energy, PNM Resources, Platte River Power Authority, and Tri-State Generation and Transmission Association. The Navajo Transitional Energy Company (NTEC) also owns a 7% stake in the Four Corners plant.

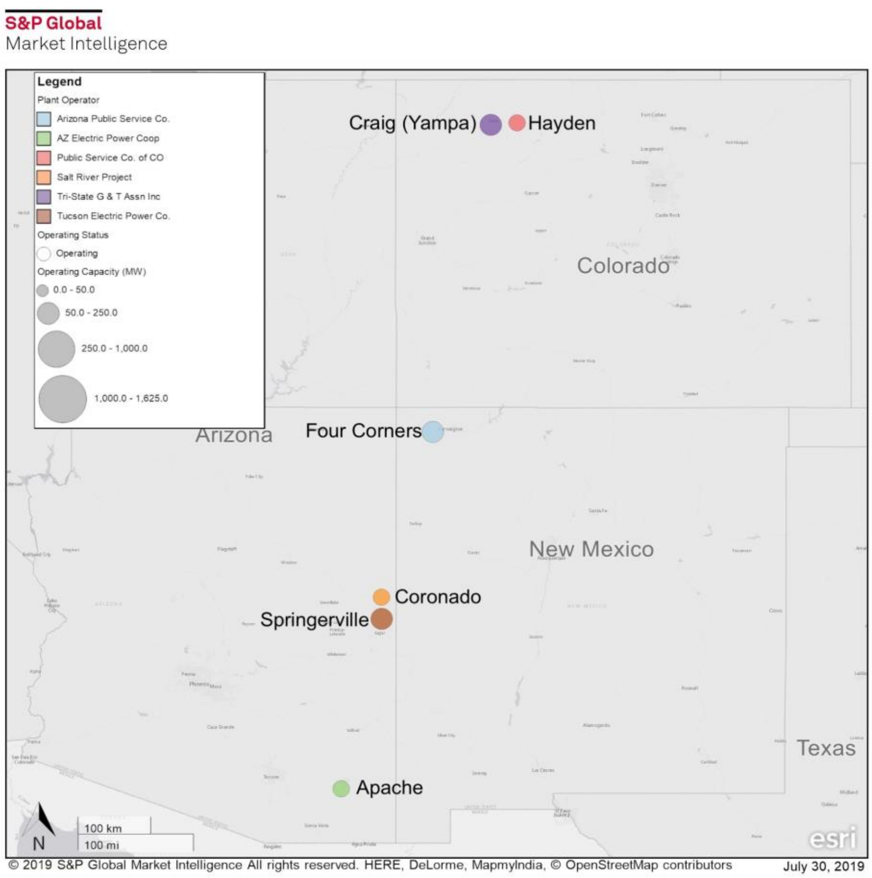

Figure 1: Analyzed coal-burning generation units serving Arizona consumers

The Cholla (1,021 MW) and Navajo (2,250 MW) coal-burning plants also serve Arizona with a combined total capacity of 3,271 MWs. Cholla has four units, one of which retired in 2015, and one that is scheduled for retirement in 2020. The final two units are scheduled for retirement in 2025. Navajo has scheduled the retirement of all three of its units by the end of 2019. As such, we excluded these five operating Navajo and Cholla units from our analysis. The 11 units analyzed are all currently slated to operate through at least 2035.

Prior to 2035 however, co-owners of these plants face key decisions. For example, the coal supply agreements at Craig, Hayden, and Four Corners expire in 2020, 2027, and 2031, respectively. The agreements would either need to be renewed or a new fuel supply would need to be secured for the plants to continue operating. Additionally, Salt River Project has a transmission service agreement with the Western Area Power Administration to deliver power from Craig, Hayden, and Four Corners that could expire in 2024 unless it is renewed.

Plant – Unit	Operating Capacity (MW)	Owner	Online Date	Currently Planned Retirement Date
Apache 3	325	Arizona Electric Power Cooperative Inc.	1979	2035
Coronado 1	380	Salt River Project	1979	None Announced
Coronado 2	382	Salt River Project	1980	None Announced
Craig 2	428	SRP (29%), TSG&T (24%), Platte River (18%), PacifiCorp (19.28%), Xcel (9.72%)	1979	2039
Four Corners 4	770	APS (63%), PNM (13%), SRP (10%), NTEC (7%), TEP (7%)	1969	2038 (APS), 2031 (TEP)
Four Corners 5	770	APS (63%), PNM (13%), SRP (10%), NTEC (7%), TEP (7%)	1970	2038 (APS), 2031 (TEP)
Hayden 2	262	SRP (50%), Xcel (37.4%), PacifiCorp (12.6%)	1976	2036
Springerville 1	387	Tucson Electric Power Company	1985	2040
Springerville 2	406	Tucson Electric Power Company	1990	2045
Springerville 3	417	Tri-State Generation & Transmission Association, Inc.	2006	None Announced
Springerville 4	415	Salt River Project	2009	None Announced
Total	4,942			

Table 1: Operating Capacity, Ownership, and Retirement data for all studied units

Of the six plants included in this analysis, Springerville is the largest and is owned and operated by TEP. In December 2016, TEP purchased an undivided ownership in the common facilities at the plant and is party to a lease agreement with the other two plant owners (SRP and Tri-State) that expires in January 2021. If the common facilities leases are not renewed, the other parties may be obligated to buy a portion of these facilities or continue to make payments to TEP for their use of the plant. Thus, the terms of any lease extension or purchase could have implications for the retirement or future use of Springerville's facilities by parties other than TEP.

3. Comparative Cost Assessment of Arizona Coal Units

3.1. Overview

A cash flow analysis was used to calculate the cost of generating electricity from 11 coal-burning generation units at six power plants serving Arizona electricity customers. The methodology for this analysis is described in Appendix A, while key assumptions are described in Appendix B.

The analysis estimated the electricity generation costs of three resource comparison portfolios: (1) market purchases; (2) solar PV paired with battery storage (supplemented by market energy purchases); and (3) wind generation supplemented by capacity purchases (all replacement options are further characterized in Appendix A). The analysis compared generation costs in terms of both the LCOE (in $/MWh) as well as the NPV of total costs in 2019 dollars. We also conducted this analysis for a scenario including a hypothetical carbon price.

3.2. Levelized Cost Comparison

Based on our projections of costs through 2050 under a "business as usual" scenario, the LCOE for coal units serving Arizona ranges from the mid $40s per MWh for the Coronado units to the mid $60s per MWh for Four Corners. Among all coal-burning units in Arizona, the LCOE of generation is highest for the Four Corners units, both of which have already been in operation for about 50 years.

For a simple initial comparison, we compared the coal unit costs (in LCOE terms) to the costs of recent new wind projects in the eastern New Mexico region[10] and a recent new solar plus storage project in the central Arizona region.[11] An incremental transmission cost was added to the wind power purchase agreement (PPA) to reflect the cost of new transmission assets or wheeling charges that may be necessary to deliver renewable energy resources from New Mexico, which rendered the wind resource more expensive than the continued operation of one coal unit. Meanwhile, replacing coal-burning generation with market energy purchases or solar plus storage is significantly cheaper than all coal units.

[10] Based on SPS' recent procurement of the Sagamore and Hale wind projects with appropriate adjustments made for the phase out of the federal production tax credit. See Appendix A for more details.
[11] Based on the Central Arizona Project's recent procurement of a 20 MW solar plus 60 MWh storage facility. See Appendix A for more details.

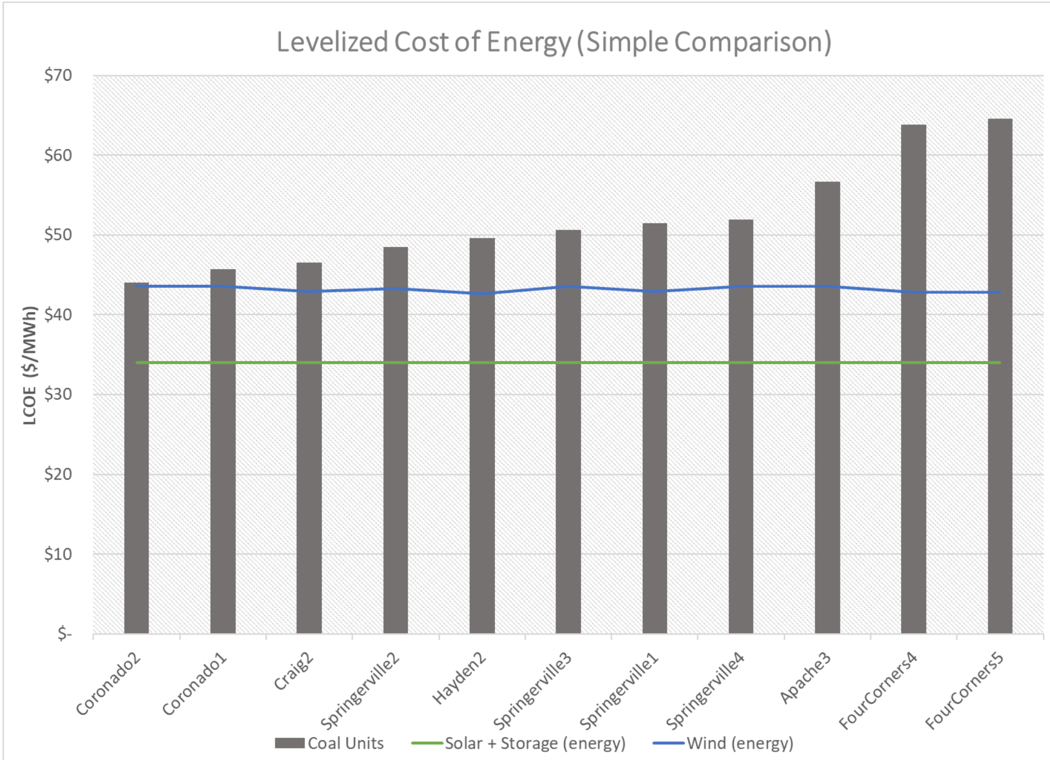

Figure 2: LCOE of coal units (2019 through 2050, or expected retirement date if sooner) compared to Sagamore Wind Energy PPA rate (with a transmission cost adder) and the solar plus storage PPA estimated by the Central Arizona Project (energy only)

While a simple LCOE comparison of wind and solar prices is useful, it does not fully capture the fact that individual wind and solar resources provide different capabilities than conventional fossil resources in terms of the availability of energy and capacity. Figure 3, below, compares the coal unit costs to three different "replacement resources" designed to provide an equivalent amount of energy and peak capacity as each of the coal units. Since wind resources are generally higher in energy value (i.e., higher capacity factor relative to solar), the wind replacement was sized to yield equivalent energy (MWh) as the coal unit and supplemented with market purchases to provide equivalent capacity (MW).[12] In contrast, since solar resources are generally higher in capacity value (i.e., higher effective load-carrying capability, or ELCC, value relative to wind), the solar replacement was sized to yield equivalent capacity (MW) as the coal unit and supplemented with market purchases to provide equivalent energy (MWh). Storage dispatch was optimized to minimize the cost of purchasing additional energy from the grid.

Furthermore, the second unit of the Coronado plant was assumed to install Selective Catalytic Reduction to control emissions that contribute to regional haze. Assuming a $110 million installation cost in 2029[13], and a 20-year lifetime, the installation increases the LCOE of the unit by approximately $2.80 per MWh.

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[12] For many years, a significant amount of excess generation capacity has existed near the Palo Verde and Mead trading hubs and may be available for purchase as a capacity resource. The amount of excess capacity has diminished in recent years through asset purchases and long-term contracts however a portion of uncontracted capacity still remains.

[13] See: https://www.azcentral.com/story/money/business/energy/2016/07/21/partial-shutdowns-proposed-srp-salt-river-project-coronado-generating-station-coal-plant-northern-arizona/87389718/

On August 20, 2019, the Environmental Protection Agency (EPA) issued new guidance to help states prepare for the second implementation period of the federal regional haze program. This new guidance puts emphasis on "discretion and flexibilities" for complying with long-standing mandates to protect visibility in federal areas. More specifically, EPA recommended that "visibility is the ultimate focus of the program and states ought to consider that against the costs and other impacts associated with the control measures." In the draft guidance, there was a recommendation that the older coal-burning power plants like Coronado, which were regulated under the first 10-year State Implementation Plan (SIP) period, could be forced to apply even more stringent pollution controls. This language is gone in the final guidance. Another recommendation reminds states they do not have to do everything during this 10-year period.[14] However, based on our analysis, a solar and storage resource remains more economic than the second unit of the Coronado plant, even in the absence of a regional haze control requirement.

Finally, the Four Corners plant has a coal supply agreement with the Navajo Transitional Energy Company through 2031. The agreement initially required a minimum tonnage of approximately 5.2 million tons per year but was amended in the summer of 2018 to reduce the coal tonnage to approximately 4.7 million tons each year. The minimum tonnage falls below that level in later years. If the plant retires before 2031, the operators will still have to pay for the minimum tonnage per year. Thus, although the LCOE in Four Corners is high, the levelized cost of an alternative would have to be significantly lower to compare favorably to the coal unit, due to the cost of the continuing coal supply obligation. Figure 3 presents the avoided LCOE in case of retirement (full height of the bar for Four Corners), as well as the reduction in this benefit by the unavoidable cost of the coal supply agreement (dotted bar is a negative benefit, subtracting from the total potential benefit of retirement). Our analysis indicates that the Four Corners units are uneconomic when compared to other options, even when the "must take" provisions of the coal supply obligation are accounted for. Their retirement could free up transmission that will allow Arizona to access more renewable energy options.

[14] https://www.law360.com/articles/1190628/4-takeaways-from-epa-s-regional-haze-rule-guidance?copied=1

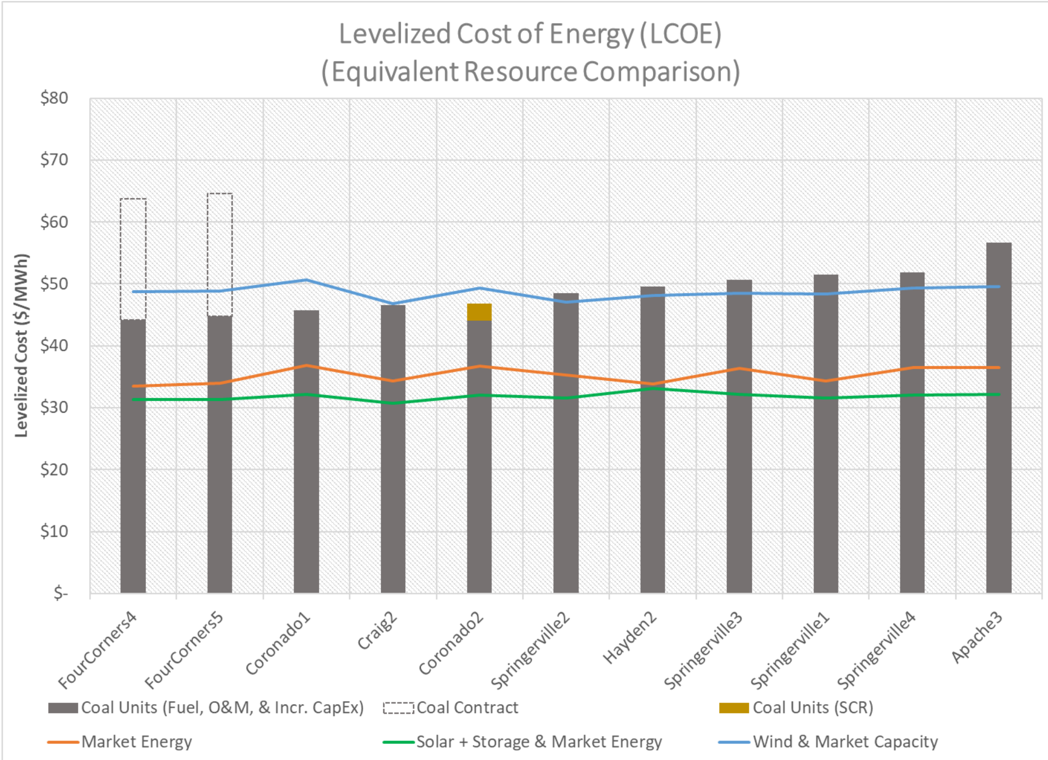

Figure 3: LCOE of coal units (2019 through 2050 or expected retirement date if sooner) versus replacement resource options. Replacements include: 1) forward market purchases (energy only), 2) solar PV plus storage supplemented with market energy purchases, 3) wind energy supplemented with market capacity purchases. A 2023 replacement start date was assumed.

Of the plants being considered, the analysis of Four Corners is worth further attention for several reasons:

1. After the retirement of Navajo Generating Station, Four Corners will be one of the largest coal-burning power plants serving Arizona customers.
2. The plant is located in a critical location for delivery of high-quality wind energy resources from central and eastern New Mexico to markets in Arizona and California. Continued operation of the plant creates a bottleneck on the transmission system that may prevent Arizona from accessing a more diverse portfolio of clean energy resources (especially wind) without construction of costly new transmission lines.
3. The plant is a significant limiting factor in the ability of Arizona utilities to invest in additional low-cost solar, due to concerns about overgeneration resulting from the minimum generation characteristics of baseload units.
4. APS currently intends to operate the plant through 2038, though other owners have indicated their plans to exit the plant on a more accelerated timeline.

Our analysis indicates that the Four Corners units are uneconomic when compared to other options, even when the "must take" provisions of the coal supply obligation are accounted for. Their retirement could free up transmission that will allow Arizona to access more energy options, as well as alleviate concerns associated with overgeneration of solar.

The analysis concludes that operating any coal unit is more expensive than other alternatives examined.

3.3. Coal Replacement Analysis: Operations, Maintenance, and Incremental Capital Expenditures

In total, the retirement of the 11 units examined results in avoided costs of $10 billion (NPV) in fuel, operation and maintenance (O&M), and capital expenditures (prior to replacements). Some replacement options come in at a significantly lower cost and can thus provide net benefits to Arizona ratepayers.

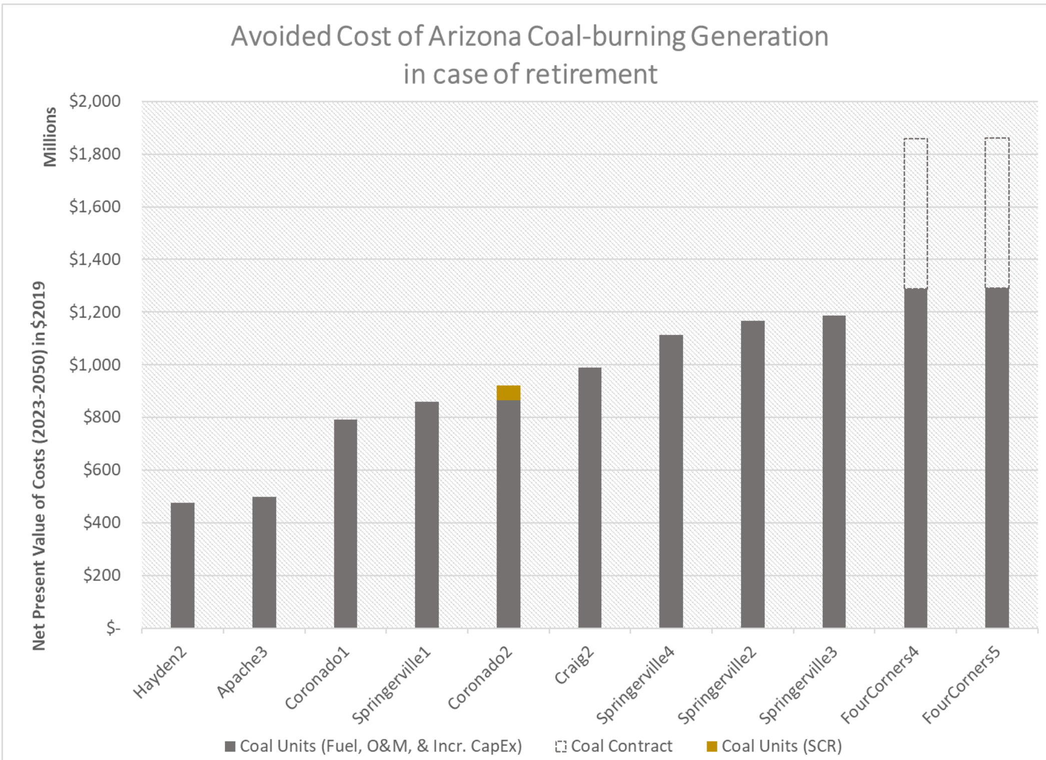

Figure 4: NPV cost for continued operation of Arizona's coal-burning fleet from 2019 through 2050 (or announced retirement date if sooner). Includes total operating and incremental capital costs and depreciation expenses of coal-burning generation units. Assumes currently announced retirement dates for all units.

Replacement with a combined Solar PV and Storage Resource

For the second replacement portfolio, the NPV of incremental costs (or savings) was projected from replacing each of Arizona's coal units with a solar PV resource with storage. The paired resource was complemented with market energy purchases in instances that the resource cannot meet the coal output. Storage was assumed to only charge from the solar resource and dispatch optimally to minimize the cost of additional energy purchases. The resource matched both the peak capacity value and energy provided by the coal unit (see Figure 6). This solar and storage "replacement resource" is further characterized in Appendix A.

For example, replacing the 175 MW Apache 3 unit with an equivalent-capacity resource requires a 220 MW-ac solar PV resource paired with storage. This resource is estimated to replace about 62% of the coal unit's energy. The remaining energy is accounted for through market energy purchases so that the solar resource provides equivalent energy and capacity as the coal unit it is replacing. The majority of those purchases (83%) happen during off-peak hours.

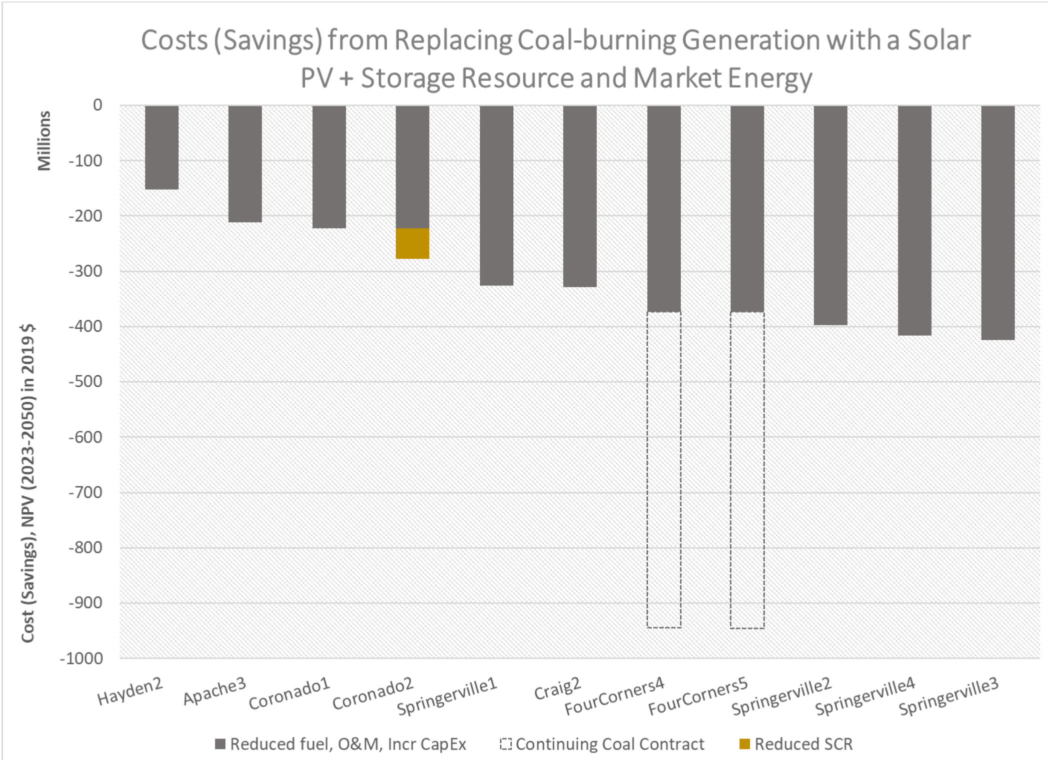

Figure 5: NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with a solar PV resource starting in 2023 that provides equivalent energy and capacity. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

We estimate that replacing all 11 coal units with solar resources in this fashion could yield approximately $3.5 billion in total savings (NPV).

Replacement with Market Purchases

The NPV of incremental costs (or savings) was projected from replacing the generation of each coal unit on an hourly basis with forward market purchases based on the Palo Verde forward index (OTC Holdings). This market purchase "replacement resource" is characterized in [Appendix A](#) below.

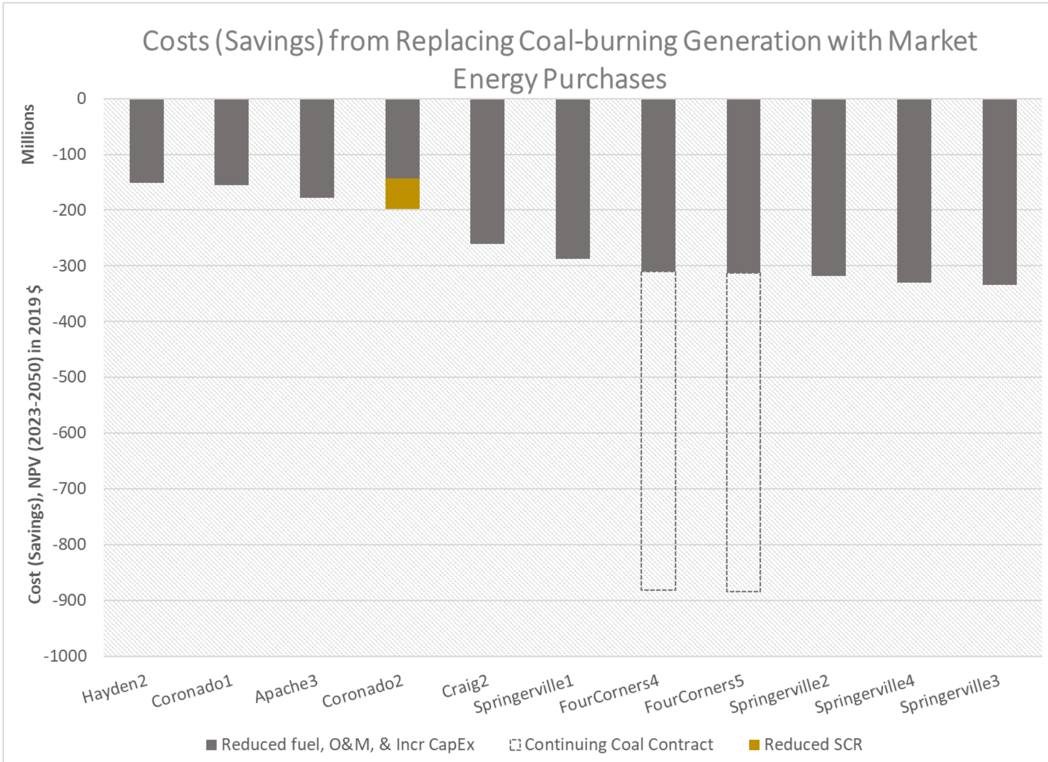

Figure 6: NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with Forward Market Purchases starting in 2023. Negative values correspond to potential benefits for the plant owner's customers.

Cost savings were observed for replacing all of the units with market purchases starting in 2023. Total cost savings were calculated to amount to $2.8 billion.[15]

Replacement with Wind

For the third replacement portfolio, the NPV of incremental costs (or savings) was projected from replacing each of Arizona's coal units with a wind resource, combined with additional market capacity purchases, to provide an equivalent resource starting in 2023 (see Figure 7). This wind "replacement resource" is further characterized in Appendix A.

For example, replacing the 891 GWh of annual production from the Apache Unit 3 with an equivalent-energy resource requires approximately a 231 MW-ac wind resource (assuming a 44% capacity factor). This resource is estimated to provide about 70 MW in terms of capacity value (based on a 30% wind capacity credit).[16] The remaining 216 MW were accounted for through capacity purchases to provide an equivalent resource in terms of both energy and capacity.

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[15] The market replacement option does not provide an equivalent resource, as it does not necessarily reflect firm capacity. Thus, expected savings might be lower.

[16] Based on the APS IRP Stakeholder Meeting presentation in April 2019, 30% approximates the capacity value of a wind resource in New Mexico.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

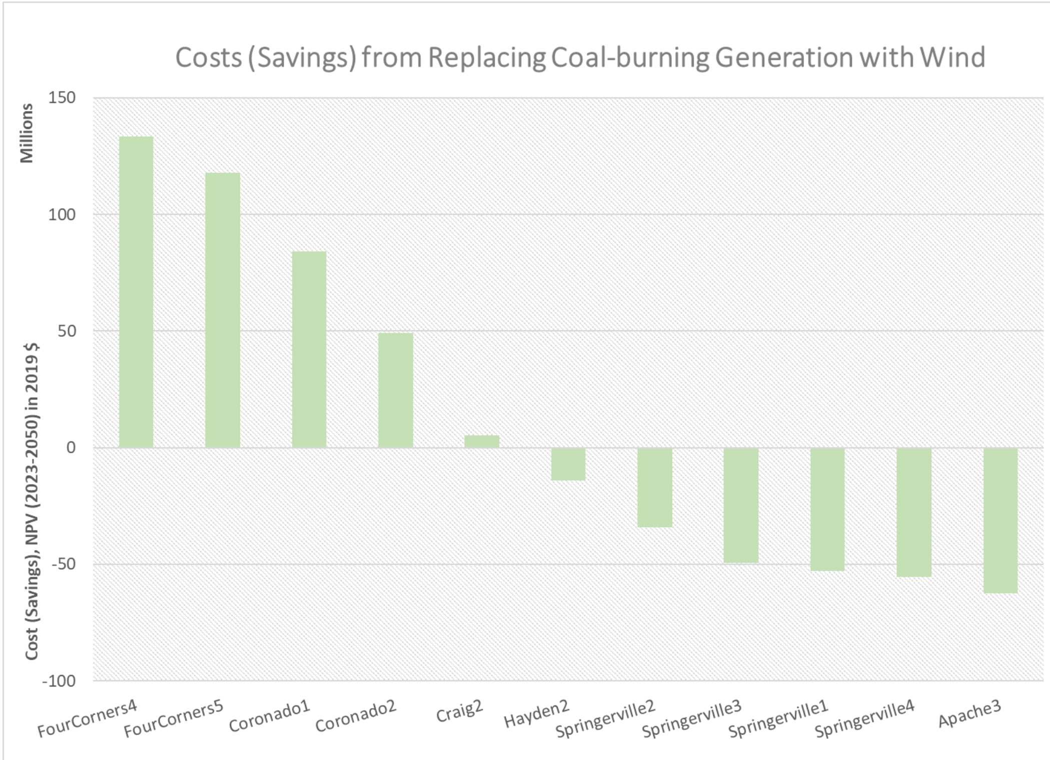

Figure 7. NPV (2023-2050) of total costs (benefits) in 2019$ from replacing coal generation with a wind resource starting in 2023 that provides equivalent energy and capacity. The green bars encompass the O&M and incremental Capital expenditure costs/savings for each unit, as well the impact of the coal contracts in Four Corners and that of the SCR installation in Coronado. They are presented as a single number for the sake of clarity. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

Although a New Mexico wind PPA is estimated to be significantly lower than the LCOE of the coal units, the addition of the transmission cost, as well as the fact that the Production Tax Credit is phasing out, renders this replacement option more expensive than the other replacement options. However, it does still yield savings in comparison to continuing operation of some of the coal units. Replacing the four units of the Springerville plant, as well as unit 3 of the Apache plant, and unit 2 of Hayden with a wind resource results in total savings of $263 million.

The results are sensitive to the transmission cost assumption. Absent additional transmission cost, the replacement of all coal units with wind resources would result in savings for Arizona ratepayers. One option that was not fully investigated in this analysis would be the replacement of the units with Arizona wind. Although, the quality of the resource in Arizona might be lower than wind in New Mexico, newer technologies with higher hub height might enable increased generation, which would make Arizona wind a realistic alternative to ratepayers while eliminating considerations of additional transmission cost from New Mexico. Secondly, adding wind increases the diversity of resources, which increases its value, especially as wind and solar have different generation profiles and can be complementary to each other. Finally, the retirement of Four Corners could open up transmission capacity that could potentially be used to transfer wind from New Mexico to Arizona at a lower cost.

3.4. Carbon Pricing Risk Assessment

In addition to projecting operating costs and capital expenditures of coal-burning generation in Arizona, Strategen conducted an analysis of the societal costs associated with greenhouse gas emissions from the plants. As described in Appendix A, we assumed a carbon price of $15.99 per short ton in 2025, which is the price specified in the APS 2017 Integrated Resource Plan. In accordance with that plan, this analysis escalated the carbon price at an annual rate of 2.5%. A discount rate of 3% was applied to these carbon costs in the NPV analysis, which is reflective of a societal discount rate more typically used for carbon cost analysis.

Requiring coal plants to internalize the cost of carbon pollution through the application of a carbon price increases the total costs for Arizona's coal-burning generation units, adding to the benefits of the three replacement options. Figure 8 compares the cost of energy for each coal unit with alternatives on a levelized basis with the addition of the carbon cost (maroon bar). For market energy purchases (including those associated with the solar PV replacement resource), a carbon price that equates to the emissions associated with a natural gas combined cycle unit was applied.[17]

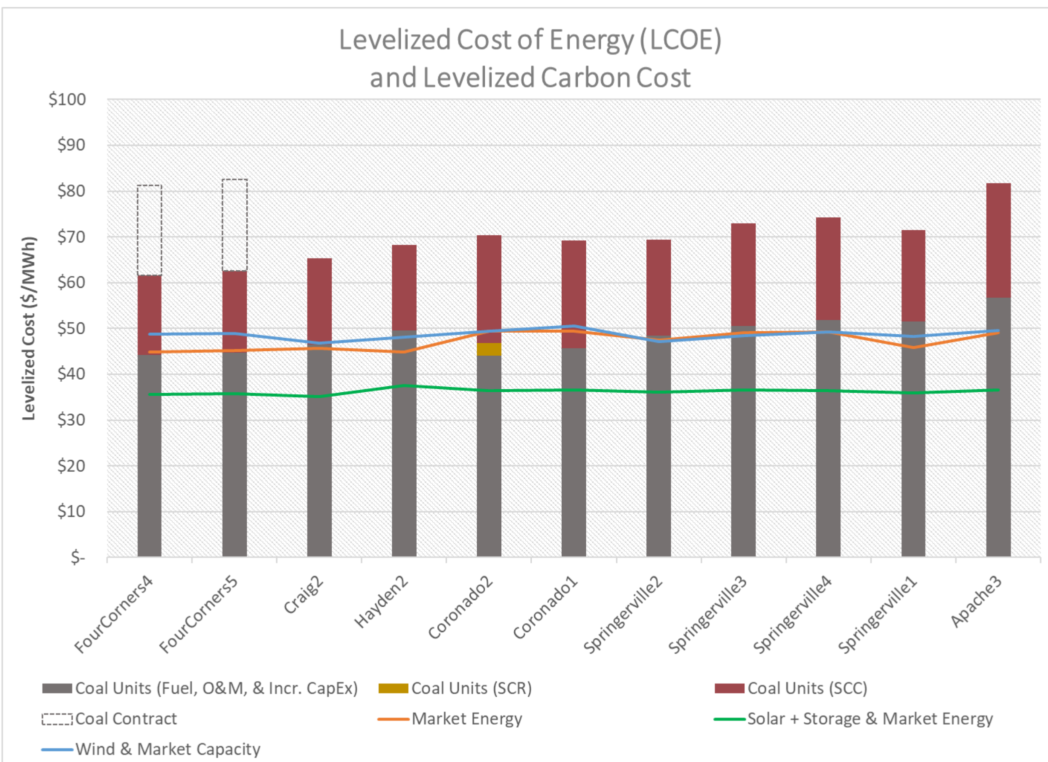

Figure 7: LCOE of coal units with added levelized carbon cost versus replacement resource options. The gray bars represent the operating costs (and incremental capital costs) of the plant, while the maroon bars represent the cost of carbon.

[17] As a simplifying assumption we assume that the marginal unit available for market purchases would most typically be a natural gas combined cycle unit. We also assume a heat rate of 7,649 BTU/kWh consistent with the following: https://www.eia.gov/electricity/annual/html/epa_08_02.html

The NPV analysis was conducted for the wind and solar replacement resources with the inclusion of a hypothetical carbon price. In all cases, adding the carbon cost substantially increases the NPV costs of coal units. It also adds to the market energy replacement option, as such energy is not necessarily clean.

Figure 8 illustrates the total societal costs and benefits through 2050 (NPV) of replacing all 11 coal units with the solar PV plus storage replacement option in 2023 once the carbon price was factored in. The total net benefits of this scenario exclusively from avoided carbon costs are found to be $6.9 billion. The equivalent resource of solar plus storage is not completely carbon free due to the additional energy purchases. Even so, total benefits from replacing coal burning generation with solar plus storage, including both operating costs and carbon costs, can bring about $10.2 billion in benefits.

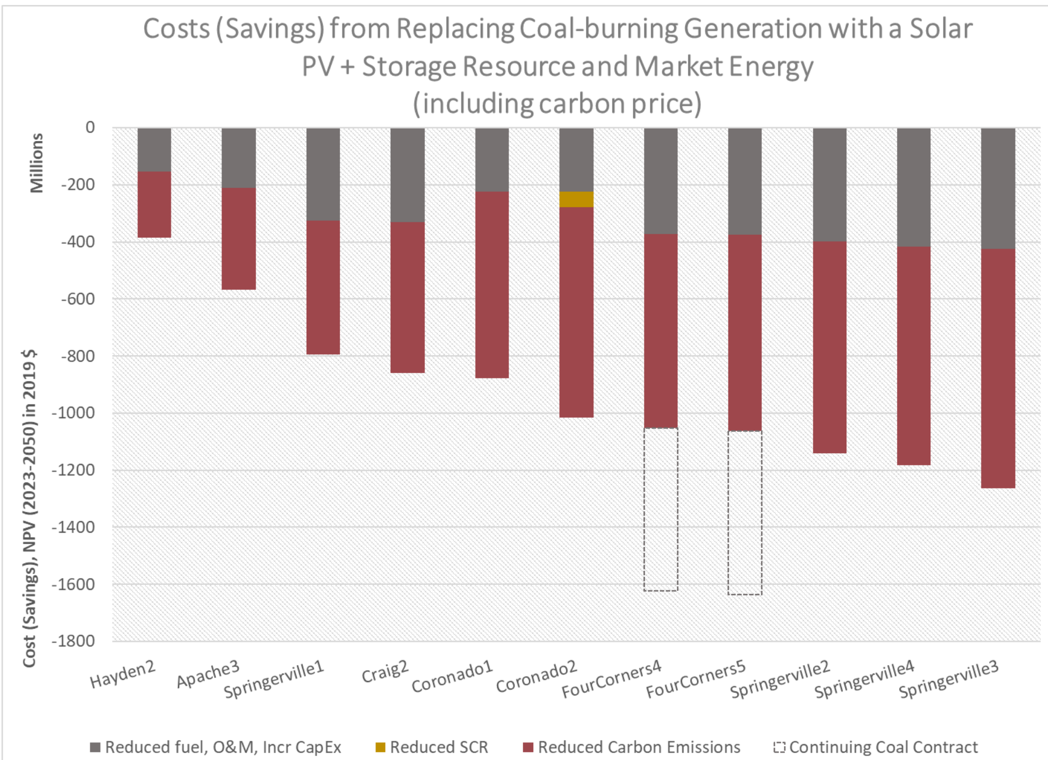

Figure 8: Savings in NPV from retiring coal units in 2023 compared to the solar PV plus storage replacement resource, when factoring in a carbon price.

Figure 9 illustrates the total societal costs and benefits through 2050 (NPV) of replacing all 11 coal units with the wind replacement option in 2023 once the carbon price was factored in. Even though replacing coal-burning generation with a wind resource was not found to be economic for all units without factoring in the carbon emissions cost, once we accounted for a carbon price, the wind option became more economic than coal-burning generation for all units. The total net benefits of retiring all 11 units to this scenario are $7.3 billion.

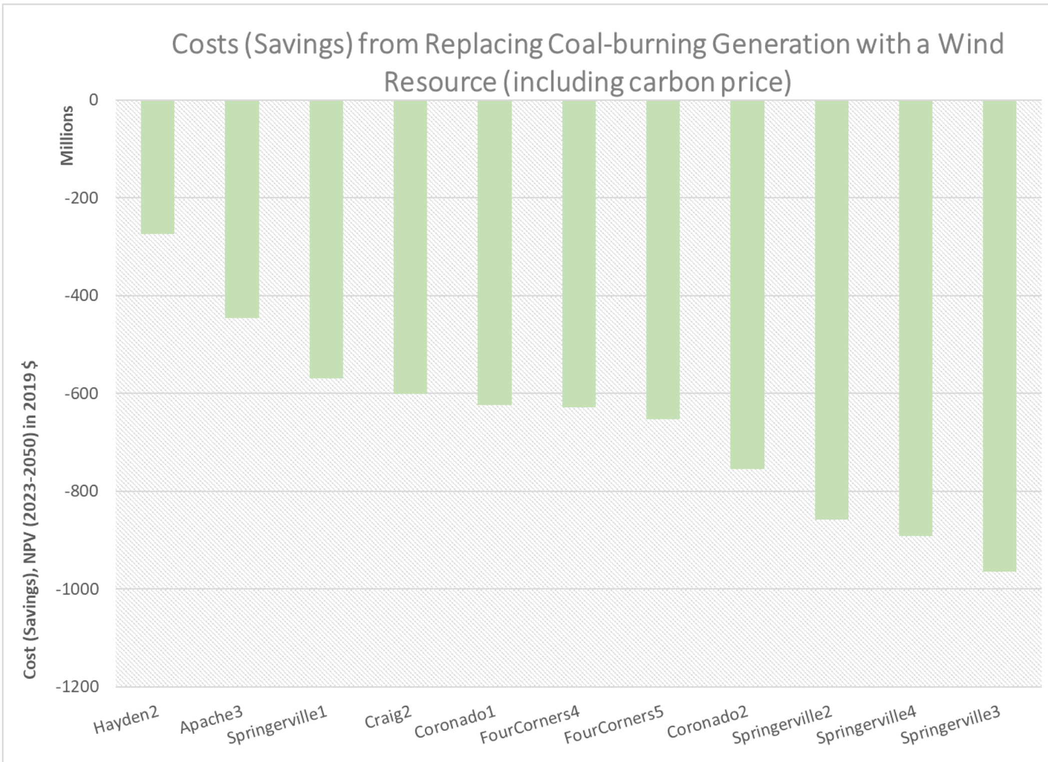

Figure 9: Savings in NPV from retiring Arizona coal generation units in 2023 compared to the wind replacement, when factoring in a carbon price.

3.5. Stranded Costs Analysis

Accelerated retirement of existing coal plants has the potential for significant ratepayer savings, simply by replacing the high operational costs of coal with cheaper, cleaner options as already analyzed in this study.

However, existing plants can have a substantial amount of capital invested in the plant that has not yet been fully depreciated. This capital invested in a plant is a cost that ratepayers have to pay if the plant continues to operate. However, in the case of a unit retirement, regulators have options to treat the remaining value of investment differently and potentially achieve even higher savings for ratepayers, beyond those previously quantified in the study.

Regulators may choose to let the utility continue to charge customers the full rate of return for capital invested in the plant and continue depreciating the plant as if it continued to operate, an option that would result in neither an increase nor a decrease in costs to ratepayers versus the status quo. However, other options available to regulators include the accelerated depreciation of the plant (potentially increasing rates in the near-term but getting the regulatory asset off the books quicker), the exclusion of some investments in the plant from earning a rate of return (if making such investments in an uneconomic plant was determined to be imprudent), or refinancing the unrecovered plant value at a lower interest rate, using a ratepayer-backed bond. All those options can result in significant ratepayer savings, in addition to the savings from O&M and fuel costs discussed earlier in the study.

To better understand the additional ratepayer savings that might result from one of those options, we looked at the refinancing option for the first unit of Springerville. Refinancing of a utility-owned asset like this can generally be done through the issuance of ratepayer-backed bonds which are used to repay the remaining undepreciated plant costs and decommissioning costs (net of salvage value). This mechanism is called securitization.

The benefits of securitization were estimated by determining differences in ratepayer capital costs under a "business as usual" (BAU) scenario, and a securitization scenario. Under the BAU scenario, these capital costs include annual depreciation expenses, and annual return on net plant (plus a gross up for taxes). For TEP, the current rate of return was assumed to be 7.04% based on TEP's current WACC[18]. For the securitization scenario, a 20-year bond was assumed with a starting value equal to the net plant balance in the year 2023, and an interest rate of 3.5%, which approximates the interest rate for a AAA-rated bond. Ratepayer costs were assumed to be equal to the principal and interest of the bond in each year of its tenor.

[18] Starting plant balance, depreciation reserve balance, and depreciation expenses for Springerville, unit 1, and TEP's current Weighted Average Cost of Capital (WACC) were based on TEP's recent rate application. Accessed at: https://docket.images.azcc.gov/0000197043.pdf

The NPV was calculated for both cases and the cost difference was estimated to be the overall benefit to TEP customers from securitization. Based on the depreciation study filed as part of TEP's 2019 rate application, the Springerville Unit 1's initial investment was $470 million, 70% of which has already been depreciated. The ratepayer benefits of refinancing through securitization were estimated to be $23 million.[19] This would be in addition to the net savings of approximately $326 million from replacing the unit with an equivalent solar plus storage option as described earlier.

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[19] While the analysis presented here represents a reasonable first approximation of the benefits of securitization, we recognize there are other factors that were not explicitly analyzed and could influence the final outcome. These include the following:

- Additional capital expenditures associated with plant common costs (only unit costs were considered)
- Additional interim adjustments to depreciation schedules or plant balances
- Adjustments to net plant balance due to Accumulated Deferred Income Taxes (ADIT) were estimated for both the BAU and securitization case, however additional information is needed for a more precise estimate.

4. Key Findings & Conclusions

Arizona utilities can realize billions in savings for their customers through an orderly retirement of their coal fleets and replacement with clean energy alternatives. As this analysis shows, it is clear that coal is no longer an economic resource for utilities in the state when compared to clean energy replacement options.

Based on our analysis of operating and incremental capital costs, the highest-cost coal-burning units serving Arizona load (on an LCOE basis) are those at the Four Corners plant. However, the existing coal supply agreement reduces the potential savings that the plant retirement could bring about. Even with lower benefits, the retirement of the fourth and fifth units of Four Corners is an economically sound decision, as the savings from O&M and incremental capital costs are very high.

When replacement options were evaluated on an equivalent peak capacity basis, the results of this analysis did not change significantly when compared to an energy-only analysis. All the plants ended up being more expensive to operate than the solar plus storage replacement, while most of them are also more expensive than wind from New Mexico despite the additional transmission cost.

Accounting for a hypothetical carbon price reinforces the economics of replacing coal-burning generation, and also makes New Mexico wind more favorable for all units.

Solar PV generation plus storage in sun-rich Arizona has the greatest potential to produce energy at a lower cost than coal-burning power, even after including market purchases to provide an equivalent amount of energy output and peak capacity contribution.

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Appendix A: Methodology

A.1. Coal Fleet Cash Flow Analysis

Strategen conducted a discounted cash flow analysis for the Arizona coal units identified in Section 2. This analysis relied upon plant- and unit-specific cost data obtained from publicly available sources as well as the S&P Global Market Intelligence database and was supplemented by unit-specific data from other sources, including regulatory filings available via the Arizona Corporation Commission.

For each coal unit, the cost elements included fuel, operations and maintenance (O&M, both fixed and variable), incremental new capital expenditures, and dismantling costs. These cost elements were projected for each year through 2050 and discounted to present value using a discount rate equal to that used in TEP's current Action Plan.[20] While the analysis extended through year 2050, we assumed unit retirements would occur based on currently announced retirement dates. In the case of Springerville units 3 and 4, there are no publicly announced retirement dates, and it was thus assumed that the units will operate until 2050. However, for the purposes of our analysis no incremental operating costs beyond 2050 were included.[21] For future years, plant output (i.e., capacity factor) at each plant was assumed to be equal to the average of the three most recent years, 2016-2018. Exceptions to this assumption include the Coronado plant which according to SRP's 2018 Integrated Resource Plan (IRP) will curtail operations during non-peak months as a result of an agreement with the EPA in lieu of installing additional emissions reduction equipment to Unit 1.[22] For this reason, when projecting the generation of the first unit of Coronado in the future, a heavier weight was given to later years when lower generation was reported compared to earlier years. The calculation of the generation of Four Corners Units 4 and 5 was also adjusted as the units were down for prolonged periods in 2017 and 2018.

Non-fuel O&M costs were estimated based on plant-level data collected from S&P Global for years 2016-2018 and escalated at an assumed annual rate of inflation (1.8%).[23] These costs are based on data reported in EIA Form 923 and FERC Form 1. Similarly, fuel costs were based on inflation adjusted averages of the previous 3 years' reported fuel costs for each plant and escalated each year at the inflation rate.

Dismantling costs for Craig Unit 2 and Hayden Unit 2, were based on documents filed by Xcel with the Colorado Public Utilities Commission. A cost per MW average of these units was calculated and used to estimate the dismantling costs of other units.

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[20] Tuscon Electric Power, 2018 Action Plan Update.
Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[21] As such, the avoided fuel and O&M costs for Springerville 3 & 4 might be conservative.

[22] Salt River Project, Integrated Resource Plan Report 2017-2018.
Accessed at: https://www.srpnet.com/about/stations/pdfx/2018irp.pdf

[23] Some plants in Arizona have recently experienced extended outages due to operational issues (e.g. Four Corners). For these plants, years containing extended outages were excluded. Costs in the remaining years were benchmarked against prior years in the S&P Global database to ensure that more recent cost estimates were consistent with past performance.

Incremental capital expenditures were approximated based on the EIA NEMS modeling approach, which includes an annualized cost of $20/kW-yr for coal plants (in 2015 dollars), which increases by $7/kW-yr for plants over 30 years in age. Capital expenditures were assumed to decline during the years prior to retirement (whether retirement occurs early or not).

A.2. Replacement Analysis

As an initial screen, the LCOE of the coal units was compared to the LCOE of a market purchase resource, a solar PV plus storage resource, and a wind resource.

The cash flow for each coal unit was compared to several hypothetical "replacement resources" (or combinations of resources) that provided equivalent or nearly equivalent energy and capacity as the coal units. Three replacement portfolios were examined that represented different combinations of zero- or low-emissions resources – 1) forward market purchases, 2) solar PV plus storage plus market energy purchases, and 3) wind generation plus market capacity purchases. The portfolios were designed to capture a representative range of clean energy alternatives, while providing an equivalent amount of energy (MWh) as the coal unit being replaced. In addition, the wind and solar alternatives were constructed to provide equivalent capacity value (MW) as the coal unit being replaced. In each replacement case, the analysis assumed that the coal unit would operate until December 31, 2022, at which point the replacement resource would be placed into service. Replacement resource cost information was based on publicly available reports and data sources, as explained below.

Fuel supplies for at least three of the coal plants examined, Craig, Hayden, and Four Corners are currently subject to Coal Supply Agreements, ending in 2020, 2027, and 2031 respectively. While Strategen is not privy to the exact terms of these contracts, it is possible that they include "take or pay" provisions that are common to many Coal Supply Agreements. Strategen examined the impact of the Four Corners Coal Supply Agreement, as presented in the NPV Analysis. If "take or pay" provisions exist for the other two plants, we expect this would yield a modest reduction in the benefits of replacing the Hayden units prior to 2027 versus the BAU case, as the analysis has already showed for the Four Corners units.

Solar PV + Storage Replacement

A combined solar PV and storage replacement option was considered. The cost of a solar PV system was estimated assuming a fixed PPA rate of $33.99/MWh.[24] The PPA rate is based on a project that received full 30 percent investment tax credits (ITC). Absent the ITC, PPA rates could be higher. However, solar projects may qualify for the full ITC through 2019, as long as they are placed into service before 2024.[25]

The storage provides the ability to flatten the solar output across the on-peak hours, eliminating the need for a firming resource. No integration costs were assumed, while the duration of the storage was assumed to be 3.5 hours and the incremental capacity value of the combined resource was assumed to be 80% of the nameplate of the solar.[26]

The hourly MWh output of each solar PV system was estimated using NREL's System Advisor Model based on a 1-Axis tracking system being constructed near the location of each retired coal plant. The hourly generation profile of each coal unit was accessed through the S&P Market Intelligence Platform. The two were compared and in hours during which the solar output was not sufficient to cover the load otherwise served by the coal unit, additional energy purchases were assumed. Storage dispatch was optimized to minimize the cost of such additional purchases, while only being allowed to charge from the solar system. Hourly market prices were modeled as on/off peak[27] according to the forward curve at Palo Verde Index published by OTC Global Holdings (as of end of August 2019).

Below are three graphs of the average (over a year) hourly coal unit generation, solar generation, and storage charging profile. This example comes from the modeling of the third unit at Apache and includes a constraint that at least 75% of the energy used to charge the battery should come from solar.

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[24] The rate is based on a 20-year PPA for 20 MW of solar generation capacity with 60 MWh of battery storage. The bulk of the energy would be at the full contract rate of $33.99/MWh, but a portion of the energy over certain hourly thresholds will be charged at a discount rate of $19.00/MWh. Strategen used the full contract rate for all energy generated by the combined resource. Accounting for the discounted rate would result in additional savings of coal unit replacements. More information can be found at: https://www.cap-az.com/documents/meetings/2019-05-02/1754-050219-WEB-Final-Packet-Board-Meeting.pdf

[25] Internal Revenue Service Notice 2018-59

[26] The Central Arizona Project PPA is based on a minimum dispatch capability of the battery of 17MW, and a total energy capacity of 60MWh, which implies a duration of 3.5 hours. Assuming a 20% incremental capacity value for utility solar, and a 100% value for solar plus 4 hours of storage, Strategen estimates a conservative 80% capacity value for solar of 20MW plus storage of 17MW, 60MWh.

[27] On peak hours: 6am-10pm

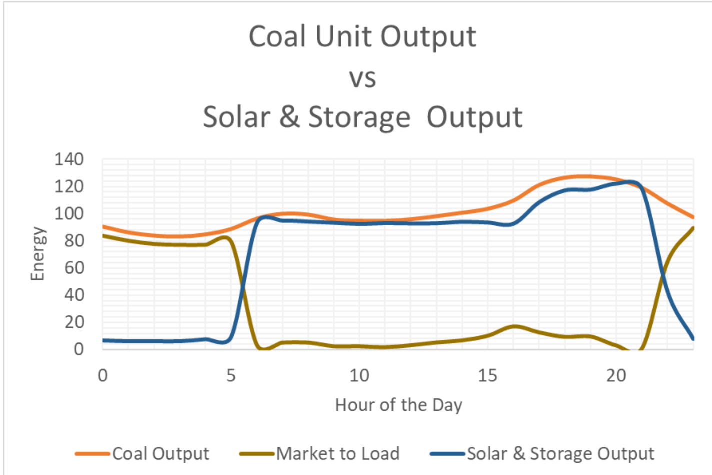

Figure 10: Coal unit output, Market Purchases to serve the load, and Solar & Storage Output

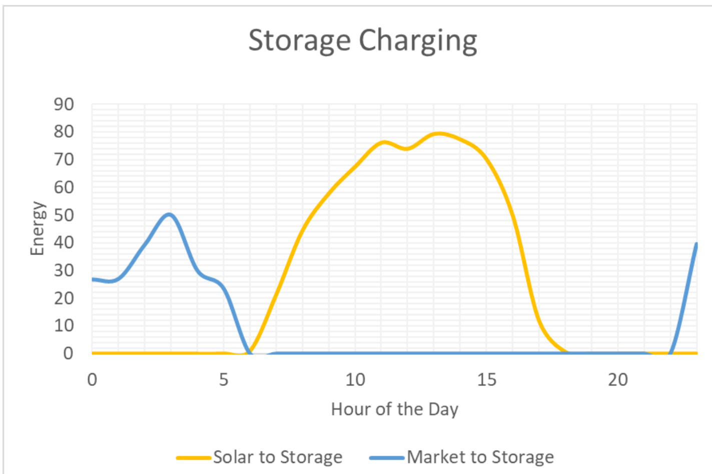

Figure 11: Storage charging profile

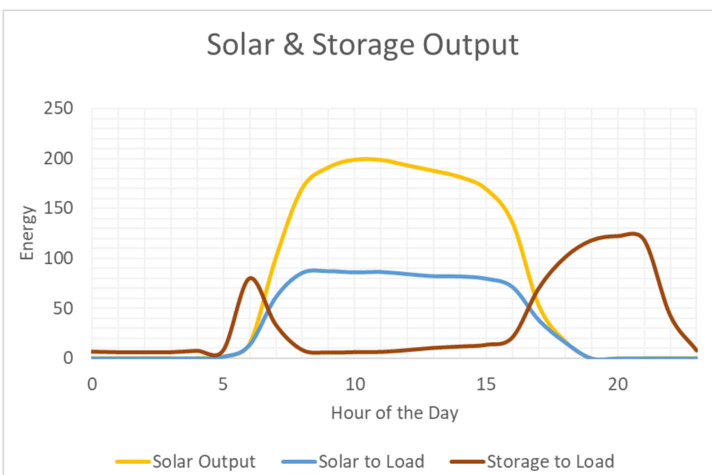

Figure 12: Solar & Storage Resource output

Forward Market Purchases

The cost of a market purchase replacement resource option was estimated based on the prices consistent with that in the Palo Verde Index published by OTC Global Holdings (as reported by S&P Global) as of end of August 2019. Annual on-peak and off-peak forward power prices were available through 2029. For the remaining periods (2029- 2050), power prices were assumed to escalate at the inflation rate. Market energy purchases were simulated to match hourly coal unit generation (as available through the S&P Global Market Intelligence database). The market replacement cost was calculated as the product of hourly prices (simulated as on/off peak Palo Verde forward prices) with the hourly coal unit generation.

Wind Replacement

A wind replacement option was also considered. The wind resource was assumed to have a capacity factor of 44%.[28] The cost of the wind generation was estimated assuming an average fixed PPA price of $18.97/MWh, escalating at 2% annually[29]. The Sagamore PPA price qualifies for a 100% Production Tax Credit (PTC). However, newer wind projects considered in this analysis would qualify for a lower PTC. Recent analysis has indicated that a substantial amount of wind projects in development for 2022 delivery have commenced construction in 2018 and would qualify for a 60% PTC.[30] Taking a conservative approach, we assumed that half of new wind resources entering service by December 2022 would qualify for a 60% PTC and half would qualify for a 40% PTC. The PPA price was thus adjusted upwards by $11.84/MWh.

Each wind system was sized to provide equivalent energy (MWh) to the coal unit being replaced. While sized to provide equivalent energy as the coal resource, a wind resource provides significantly less capacity value. As such, additional market capacity purchases were also included to ensure the MW of replacement capacity would be equal to the coal unit's capacity.

The capacity value for the wind resource was assumed to be equal to 30%, consistent with the value presented in the APS IRP Stakeholder meeting in April 2019. Additional capacity was purchased at an assumed cost of $39.48/kW-yr in 2019. This reflects an assumed blended average of $11.59/kW-yr in $2018 for short-term market purchases[31] and $69.60/kW-yr in $2021 cost for a new gas resource[32]. The capacity cost was assumed to escalate at the rate of inflation.

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[28] APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

[29] Direct Testimony of David T. Hudson on behalf of Southwestern Public Service Company, Case No. 17-00044-UT. Accessed at: http://164.64.85.108/infodocs/2017/3/PRS20236617DOC.PDF

[30] See: https://www.windpowerengineering.com/business-news-projects/more-than-61-gw-of-u-s-wind-turbine-equipment-has-qualified-for-the-ptc-since-2016/

[31] APS 2017 IRP, Table D-5.
Accessed at: https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf

[32] Average price of new gas resource according to APS 2019 Preliminary IRP
Accessed at: https://docket.images.azcc.gov/0000199276.pdf

The analysis assumed a $10/MWh transmission cost adder in 2019 reflecting the wheeling cost for transporting wind resources from New Mexico to Arizona. The adder was assumed to increase at the inflation rate.[33]

A.3. Carbon Pricing Risk Assessment

This analysis calculated the carbon cost of each coal plant's carbon-dioxide emissions using Arizona Public Service's guidelines for pricing, start date and escalation and discount rates. Based on APS parameters, the analysis set an initial carbon price at $15.99 starting in 2025, with an annual escalation rate of 2.5% and a discount rate of 3%.

[33] Consistent with the APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

Appendix B: Key Assumptions and Data Sources

Global Assumptions:

Assumption /Input	Value	Source & Description
Discount Rate	6.78%	Discount rate for Tuscon Electric Power consistent with its 2018 Action Plan 2016[34]
Inflation Rate	1.8%	Based on current inflation rate for the past 12 months (US inflation calculator)
Early Retirement Year	2023	Assuming last day of operations on 12/31/2022

Coal Plant Inputs & Assumptions:

Assumption/ Input	Value	Source & Description
Fuel Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. Average of 2016-2018 values adjusted for inflation were assumed in 2019 and escalated at inflation rate for subsequent years.
Variable O&M Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. Average of 2016-2018 values adjusted for inflation were assumed in 2019 and escalated at inflation rate for subsequent years.
Fixed O&M Costs	Varies by plant	Based on values reported (or modeled) in S&P Global Market Intelligence database. 2019 values are based on average costs of 2016-2018 adjusted for inflation. Future costs were escalated at inflation rate. Fixed O&M costs for Four Corners were averaged over 5 years as late years might be considered higher than normal due to significant down time.
Incremental Capital Costs	$20-27/kW-yr	Based on EIA NEMS model:[35] $20/kW-yr (adjusted for inflation) assumed for plants <30 years and, $27/kW-yr (adjusted for inflation) assumed for plants >30 yrs.
Dismantling Costs	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E[36] for the Craig and Hayden plants. For other units, dismantling costs were assumed to be equal to the per-MW average costs of the Xcel units.
Capacity Factor	Varies by plant	Based on average of 2016-2018 as reported in S&P Global Market Intelligence database

[34] TEP Action Plan 2018.
Accessed at: https://www.tep.com/wp-content/uploads/2018/06/TEP-Action-Plan.pdf

[35] See:
https://www.eia.gov/outlooks/aeo/workinggroup/coal/pdf/2016_EMM%20Coal%20Workshop%20Presentation%20(6-13-16).pdf

[36] See:
https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=

Retirement Date ("Business as Usual" Case)	Varies by plant	Based on utilities IRPs.[37]

Replacement Resource Inputs & Assumptions:

Assumption/Input	Value	Source & Description
Solar + Storage PPA	$33.99/MWh	Based on proposal to Central Arizona Project for a 20-year PPA for 20 MW of solar generation capacity with 60 MWh of battery storage.[38]
Wind Cost	$18.97/MWh	Sagamore PPA escalating at 2%.[39]
Wind Transmission Cost (2019)	$10/MWh	Consistent with the analysis presented at APS IRP stakeholder Meeting in April, 2019
Market Energy Prices	Varies	Based on OTC Global Holdings Forward Power Index for Palo Verde as of 30/08/2019.
Capacity Price (2019)	$39.48/kW-yr	Blended cost between short- and long- term cost of a gas resource according to APS IPR 2017 & 2019 (preliminary).

Carbon Pricing Risk Assessment Inputs and Assumptions:

Assumption/Input	Value	Source & Description
Carbon price (2025)	$16/metric ton	Based on APS's IRP carbon assumption, which is based on California price, and begins in 2025.[40]
Escalation rate	2.5%	
Discount Rate	3%	Used only for computing the net present value of the cost of carbon portion of the analysis.

[37] Arizona Electric Power Cooperative. Accessed at: https://docket.images.azcc.gov/0000179477.pdf
Tri-State Generation and Transmission Association, Inc. Accessed at: https://www.tristategt.org/sites/tristate/files/PDF/resourceplan/2015%20Electric%20resource%20plan.pdf
Arizona Public Service IRP. Accessed at: https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf
Tuscon Electric Company. Accessed at: https://www.tep.com/wp-content/uploads/2019/07/TEP-Preliminary-Integrated-Resource-Plan-070119-FINAL-Version-2.pdf

[38] See: https://www.cap-az.com/documents/meetings/2019-05-02/1754-050219-WEB-Final-Packet-Board-Meeting.pdf

[39] Direct Testimony of David T. Hudson on behalf of Southwestern Public Service Company, Case No. 17-00044-UT. Accessed at: http://164.64.85.108/infodocs/2017/3/PRS20236617DOC.PDF

[40] APS IRP Stakeholder Meeting, April 2019.
Accessed at: https://www.aps.com/library/resource%20alt/April-4-2019-IRP%20Workshop_FINAL.pdf

Appendix C: Results

Plant	Coal Units				Solar plus Storage + Market Energy	Market Energy	Wind + Market Capacity
	Fuel, O&M, & Incr. CapEx	Coal Contract	SCR	Total Cost			
Apache3	$ 498,384,272	$ -	$ -	$ 498,384,272	$ 286,907,824	$ 320,754,721	$ 436,032,796
Coronado1	$ 792,125,301	$ -	$ -	$ 792,125,301	$ 569,634,144	$ 637,059,928	$ 876,160,519
Coronado2	$ 865,626,248	$ -	$ 54,951,732	$ 920,577,980	$ 642,959,355	$ 721,944,578	$ 969,637,675
Craig2	$ 989,755,707	$ -	$ -	$ 989,755,707	$ 660,437,245	$ 728,997,484	$ 994,918,447
FourCorners4	$1,858,982,946	$ (571,609,746)	$ -	$1,287,373,200	$ 914,760,152	$ 976,750,086	$1,420,784,366
FourCorners5	$1,862,499,108	$ (571,609,746)	$ -	$1,290,889,361	$ 917,060,335	$ 978,432,311	$1,408,607,970
Hayden2	$ 474,480,007	$ -	$ -	$ 474,480,007	$ 321,743,713	$ 323,440,325	$ 460,405,600
Springerville1	$ 860,548,900	$ -	$ -	$ 860,548,900	$ 534,247,461	$ 573,313,091	$ 807,809,590
Springerville2	$1,167,459,444	$ -	$ -	$1,167,459,444	$ 769,341,045	$ 849,578,346	$1,133,266,989
Springerville3	$1,187,885,222	$ -	$ -	$1,187,885,222	$ 763,685,587	$ 853,471,934	$1,138,434,270
Springerville4	$1,112,980,259	$ -	$ -	$1,112,980,259	$ 697,265,769	$ 783,214,978	$1,057,640,955

Table 2: Summary results: Avoided Cost (NPV) of coal units in case of retirement in 2023. and replacement options (by 2023). Each column represents a distinct set of and not a cumulative total. Results are in 2019$

Plant	Coal Units		Solar plus Storage + Market Energy		Market Energy		Wind + Market Capacity
	Avoided Cost in case of retirement	Avoided Carbon Cost	Resource Cost	Carbon Cost	Resource Cost	Carbon Cost	Resource Cost
Apache3	$ 498,384,272	$ 382,952,321	$ 286,907,824	$ 26,764,376	$ 320,754,721	$ 194,607,703	$ 436,032,796
Coronado1	$ 792,125,301	$ 707,538,708	$ 569,634,144	$ 53,311,340	$ 637,059,928	$ 383,166,900	$ 876,160,519
Coronado2	$ 920,577,980	$ 803,268,803	$ 642,959,355	$ 65,945,794	$ 721,944,578	$ 434,751,990	$ 969,637,675
Craig2	$ 989,755,707	$ 606,140,443	$ 660,437,245	$ 76,996,202	$ 728,997,484	$ 369,288,755	$ 994,918,447
FourCorners4	$1,287,373,200	$ 762,292,257	$ 914,760,152	$ 82,716,075	$ 976,750,086	$ 492,755,508	$1,420,784,366
FourCorners5	$1,290,889,361	$ 770,263,295	$ 917,060,335	$ 81,078,665	$ 978,432,311	$ 487,493,862	$1,408,607,970
Hayden2	$ 474,480,007	$ 259,828,776	$ 321,743,713	$ 27,776,451	$ 323,440,325	$ 152,449,979	$ 460,405,600
Springerville1	$ 860,548,900	$ 516,422,127	$ 534,247,461	$ 47,287,574	$ 573,313,091	$ 298,091,579	$ 807,809,590
Springerville2	$1,167,459,444	$ 823,666,864	$ 769,341,045	$ 81,494,684	$ 849,578,346	$ 481,808,026	$1,133,266,989
Springerville3	$1,187,885,222	$ 915,554,258	$ 763,685,587	$ 75,240,385	$ 853,471,934	$ 519,183,614	$1,138,434,270
Springerville4	$1,112,980,259	$ 836,926,208	$ 697,265,769	$ 71,165,310	$ 783,214,978	$ 474,673,440	$1,057,640,955

Table 3: Summary results: Cost (NPV) of replacing coal units with the three replacement options by 2023, including carbon cost. Each column represents a distinct set of benefits and not a cumulative total. Results are in 2019$

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