

# Colorado Coal Plant Valuation Study



Economic assessment of coal-fired  
power plants in Colorado and  
potential replacement options

Prepared For:  
Sierra Club  
June 26, 2019

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Prepared for:  
*Sierra Club*

Prepared by:  
*Edward Burgess*  
*Maria Roumpani*  
*Kevin Moy*  
*Jack Chang*  
*Sophia Ahmed*  
*Aidee Rodriguez Maza*



Strategen Consulting, LLC  
2150 Allston Way, Suite 400  
Berkeley, California 94704  
[www.strategen.com](http://www.strategen.com)

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## Executive Summary

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Coal-fired generation in Colorado is becoming less economically competitive when compared to renewable energy resources such as wind and solar, or market purchases. Already, older coal-fired units owned at least partially by Public Service Company of Colorado (which does business as Xcel Energy) have higher levelized costs of energy (LCOE) than replacement options. Newer coal-fired units such as Xcel's Comanche 3 are the most cost competitive compared to replacement options but still have high long-term costs when considered on a net present value basis. Cleaner replacement alternatives can be economically competitive with these coal-fired units while still providing equivalent energy and capacity by accessing market options. Among replacement options, wind generation already appears to be cost-competitive on an LCOE basis when compared to all of the Colorado coal units analyzed, including five owned at least partially by Xcel. Solar photovoltaics (PV) are also more competitive than nearly all of the analyzed Colorado coal units, including four units partially owned by Xcel.

For nearly all coal-fired power plants in Colorado, retirement in the 2023 timeframe and replacement with alternative resource options could provide significant economic benefits to electricity consumers due to reduced operating and maintenance costs (including fuel) and avoided incremental capital costs. Replacing all ten coal units examined with solar resources would reduce costs by \$1.4 billion on a net present value basis (NPV) and replacement with wind resources would reduce costs by \$1.7 billion. For Xcel in particular, replacing its share of five remaining coal-fired units could yield benefits ranging from \$187 million (NPV) for a solar resource replacement to \$360 million (NPV) for a wind resource replacement. More specifically, replacing Xcel's most expensive units, Hayden 1 & 2 and Craig 2, could save Xcel customers \$148 million in the case of solar or about \$156 million in the case of wind.

The benefits from retiring existing coal units are even larger when the social cost of carbon (SCC) is considered. As required by the Sunset Public Utilities Commission Act, SB 19-236, factoring in a SCC of at least \$46 per ton of carbon dioxide emitted increases the cost (on an LCOE basis) of all of Colorado's coal-fired units well above that of replacement options. When the SCC is included, the additional societal benefits of replacing all coal units in Colorado would range from \$17.7 billion (NPV) for a solar replacement to \$18.7 billion (NPV) for a wind replacement. The additional societal benefits of replacing Xcel's five remaining coal-fired units would range from \$7 billion (NPV) for a solar replacement to \$7.3 billion (NPV) for a wind replacement.

The benefits to Xcel customers from early coal retirements can also be enhanced through financing options such as "securitization." Much like refinancing a home mortgage, securitization would replace the current cost of financing existing coal plants with a lower cost bond option. Strategen estimates that replacing Xcel's coal units and using securitization would provide an additional \$467 million (NPV) in benefits to Xcel customers versus a "business as usual" scenario.

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## 1. Introduction

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Throughout the United States, and in the West in particular, falling costs for renewable energy generation have increased economic pressures on coal-fired power plants. In the Colorado Energy Plan, Xcel received bids for wind, solar, and battery storage projects that, at the time, were some of the lowest prices seen in the country. The Colorado Public Utilities Commission ultimately approved

the Colorado Energy Plan, under which Xcel will close two coal-fired units, Comanche Units 1 and 2, in favor of wind, solar and existing gas resources. Later in December 2018, Xcel announced that by 2030 it would cut its carbon emissions by 80 percent from 2005 levels in the eight states it serves. Colorado Governor Jared Polis has also pledged that the state's grid will use 100% renewable electricity by 2040.

This trend has also been playing out with other Colorado utilities. In 2016, Tri-State Generation & Transmission Association, Inc., a wholesale electric power cooperative, announced that it would retire two coal-fired units, with Nucla retiring by the end of 2022 and Craig Unit 1 retiring by the end of 2025. Nationally, in 2018 and 2019, 68 coal units with a combined capacity of 20,669 MW closed or were scheduled to close.<sup>1</sup>

In early May 2019, the Colorado legislature also passed several comprehensive energy reforms, including requiring rules to be developed to accommodate distributed energy resources and requiring the state to reduce greenhouse gases by 50% of 2005 levels by 2030 and by 90% of 2005 levels by 2050. Among those legislative changes was a requirement that state planners evaluate the social cost of carbon when making electricity and heating resource decisions. Colorado also passed legislation authorizing the use of financial tools, such as securitization, to help address potential stranded costs of retiring coal units.

These actions will undoubtedly have an effect on Colorado's generation fleet going forward. Currently, Colorado has seven coal-fired power plants, totaling 4,472 MW of generation capacity, which makes up 26% of the state's total generation capacity. Transitioning away from fossil fuel-based generation, such as coal, towards renewable resources will be necessary to meet Colorado's ambitious clean energy and greenhouse gas reduction goals. In addition, transitioning away from coal may also be warranted based on economics alone, to reduce overall costs to electricity customers, given that coal-fired power plants have become increasingly uneconomic, especially when compared to the declining costs of renewable energy.

On behalf of the Sierra Club, Strategen conducted an economic analysis to better understand which of Colorado's coal plants may be most suitable for replacement with clean energy resources. To do so, Strategen conducted a cash flow analysis examining a "business-as-usual" case of energy production at ten coal-fired generation units in the state, including five owned by Xcel. This analysis estimated the levelized costs of energy and the net present values of each coal unit's operating, maintenance, and incremental capital costs. Strategen then compared those results with the economics of three replacement portfolios: wind, solar, 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 cost of renewable energy and coal-fired power.

Additionally, the study examined two issues related to provisions of the 2019 Sunset Public Utilities Commission Act, SB 19-236. This study calculates the societal benefits of coal retirements based on the minimum values for the social cost of carbon specified in SB 19-236. The study also calculates the impact of using securitization, which would let utilities issue energy impact assistance bonds at low interest rates to finance their remaining coal-related debt.

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<sup>1</sup> Feaster, Seth, "Record Drop in U.S. Coal-Fired Capacity Likely in 2018," October 2018. [http://ieefa.org/wp-content/uploads/2018/10/Record-Drop-in-U.S.-Coal-Fired-Capacity-in-2018\\_October2018.pdf](http://ieefa.org/wp-content/uploads/2018/10/Record-Drop-in-U.S.-Coal-Fired-Capacity-in-2018_October2018.pdf)

## 2. Colorado's Coal Fleet

### 2.1 Xcel's Coal Fleet

Xcel partially or wholly owns eight different coal-fired generation units at four power plants across the state, totaling approximately 2,000 MW of Xcel-owned coal-fired generation. An additional 1,236 MW share of these eight units is owned by other utilities, bringing their total nameplate capacity to 3,228. These facilities account for about half of Xcel's company-wide coal-fired generation capacity in the eight states it serves. Almost all of Xcel's coal-fired units in Colorado are greater than 38 years old, with the exception of Comanche Unit 3, which started operations in 2010.

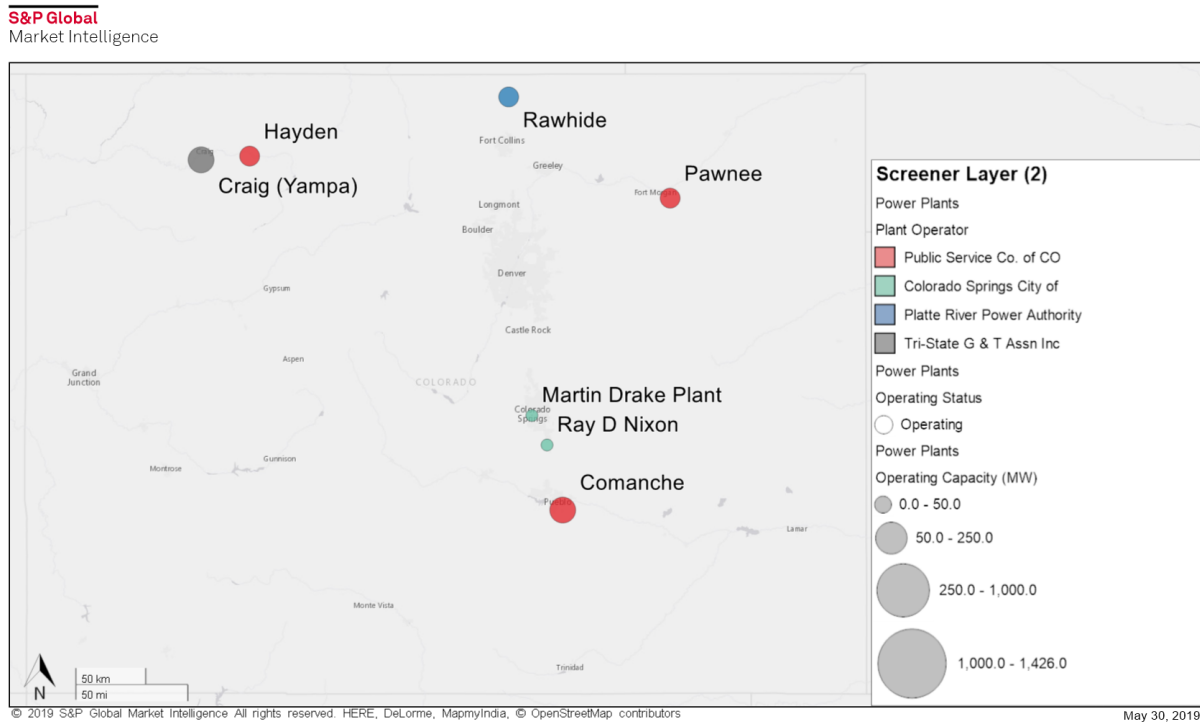


Figure 1. Coal unit locations in Colorado

Table 1. Coal units in Colorado owned by Xcel

Plant – Unit	Operating Capacity, MW	Xcel-owned Share, MW (%)	Online Date	Currently Planned Retirement Date
Comanche 1	325	325 (100%)	1973	2022
Comanche 2	335	335 (100%)	1975	2025
Comanche 3	766	511 (66.7%)	2010	2070
Craig 1	428	42 (9.7%)	1980	2025
Craig 2	428	42 (9.7%)	1979	2039
Hayden 1	179	135 (75.5%)	1965	2030
Hayden 2	262	98 (37.4%)	1976	2036
Pawnee	505	505 (100%)	1981	2041
<b>Total</b>	<b>3,228</b>	<b>1,992 (61.7%)</b>		

The Colorado Energy Plan includes accelerated retirement of two of Xcel's coal-fired generation units – Comanche 1 and 2 - with a total capacity of 660 MWs. In addition, Xcel and the other owners of Craig Unit 1 have agreed to retire the unit by the end of 2025. As such, we excluded these three units from our analysis. Apart from Comanche 1 and 2 and Craig Unit 1, Xcel currently plans to operate all of its coal units through at least 2030.

Xcel and the co-owners of these plants face key decision points in the near future. For example, the coal supply agreements at Craig and Hayden expire in 2020 and 2027 respectively. Thus, 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 currently has a transmission service agreement with the Western Area Power Administration to deliver power from Craig and Hayden that could expire in 2024 unless it is renewed.

## 2.2 Other Coal Plants in Colorado

In addition to Xcel's coal fleet, we examined the other coal units in Colorado listed below, with the exception of Nucla. Given that Tri-State has committed to retire Nucla by the end of 2022, Nucla is not included in the analysis.

*Table 2. Coal units in Colorado owned by utilities other than Xcel*

Plant – Unit	Operating Capacity, MW	Ownership (% share)	Online Date	Announced Retirement Date
Craig 3	448	Tri-State G&T (100%)	1984	None
Martin Drake 6	77	Colorado Springs Utilities (100%)	1968	2035 <sup>2</sup>
Martin Drake 7	131	Colorado Springs Utilities (100%)	1974	2035 <sup>3</sup>
Nixon	208	Colorado Springs Utilities (100%)	1980	None
Nucla	100	Tri-State G&T (100%)	1959 (Units 1-3), 1991 (Unit 4)	2022
Rawhide	280	Platte River Power Authority (100%)	1984	2046
<b>Total</b>	<b>1,244</b>			

## 3. Comparative Cost Assessment of Colorado Coal Units

### 3.1 Overview

A cash flow analysis was used to calculate the cost of generating electricity from ten coal-fired generation units at seven power plants in Colorado, including five units owned at least in part by Xcel. 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 supplemented by market energy purchases; and (3) wind generation supplemented by capacity purchases. The analysis compared generation

<sup>2</sup> Colorado Springs Utilities voted in 2015 to decommission the Drake Power Plant no later than 2035. <https://www.csu.org/pages/martin-drake-r.aspx>

<sup>3</sup> *Id.*

costs in terms of both the Levelized Cost of Energy (in \$/MWh) as well as the Net Present Value of total costs in 2019 dollars. We also conducted this analysis for a scenario including a social cost of carbon and a scenario that includes securitization of the Xcel-owned generation units.

### 3.2 Levelized Cost Comparison

Based on our projections of costs through 2050 under a “business as usual” scenario, the LCOE for coal units in Colorado ranges from approximately \$31.15 per MWh at Rawhide to \$53.37 per MWh at Craig 3. Among all coal-fired units in Colorado, the LCOE of generation was highest for the Craig and Hayden units. Both of those plants rely on coal mined from the Rocky Mountain Colorado Rail location, where coal prices are significantly higher (as high as \$50.46 per ton in 2018) than coal from the Powder River Basin Wyoming Rail location (as low as \$20.46 per ton in 2018).<sup>4</sup> For a simple initial comparison, we compared the coal unit LCOE numbers to the Xcel Energy 2017 All Source RFP bid prices for wind and solar PV (adjusted for 2019 as described in Appendix A). Wind compares favorably to all of the coal units, while solar PV compares favorably to all of the coal units with the possible exception of Rawhide, which is roughly equal in cost.

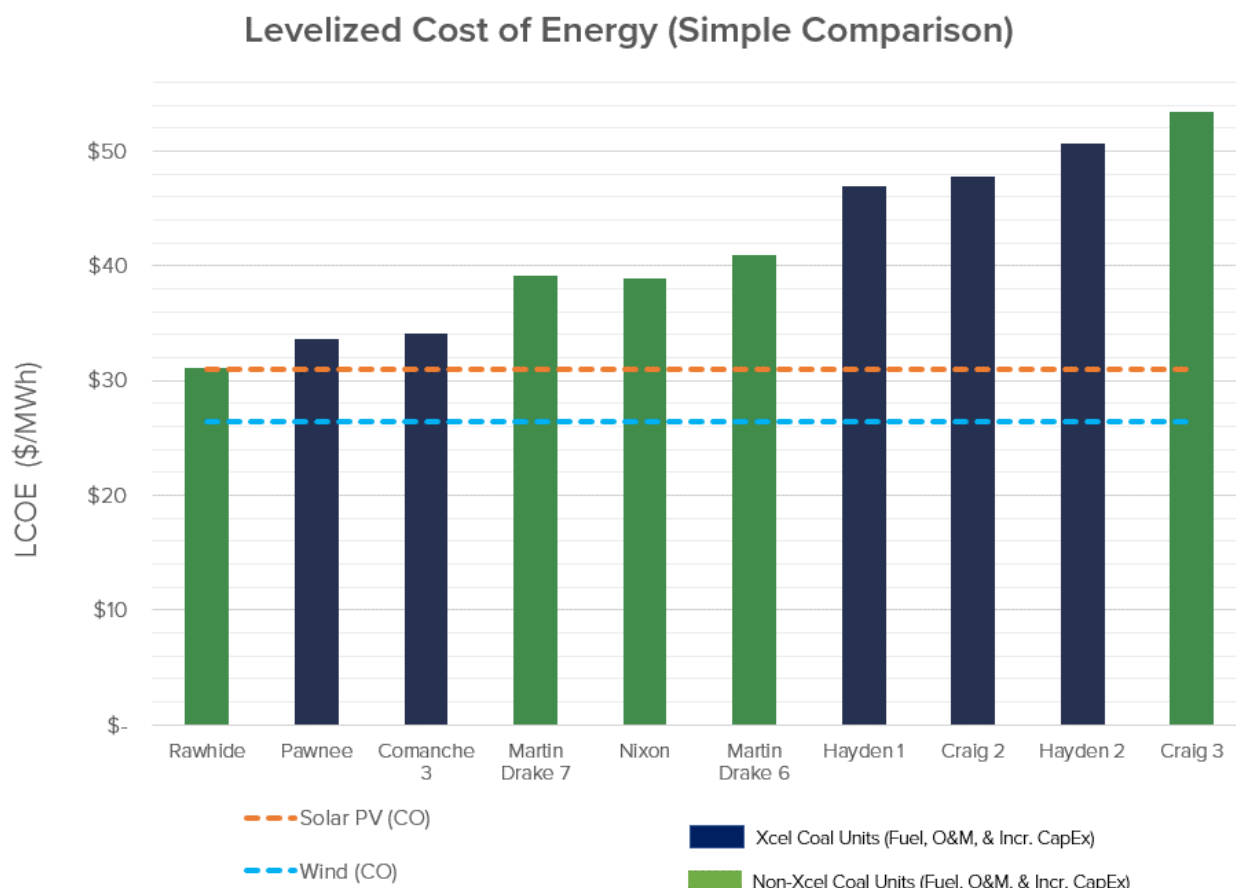


Figure 2. LCOE of Colorado coal units (2023 through 2050, or expected retirement date if sooner), compared to the Xcel Energy 2017 All Source RFP wind and solar PV median bid prices (energy only, w/ adjustments for 2023 delivery as described in Appendix A).

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

<sup>4</sup> Based on S&P Global Market Intelligence data.

unit costs to three different “replacement resources” designed to provide an equivalent amount of energy and 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). In contrast, since solar resources are generally higher in capacity value (i.e. higher 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).

As shown below, the wind replacement resource is cheaper than all of the coal units. The solar PV replacement resource is cheaper than all of the coal units except for Rawhide.

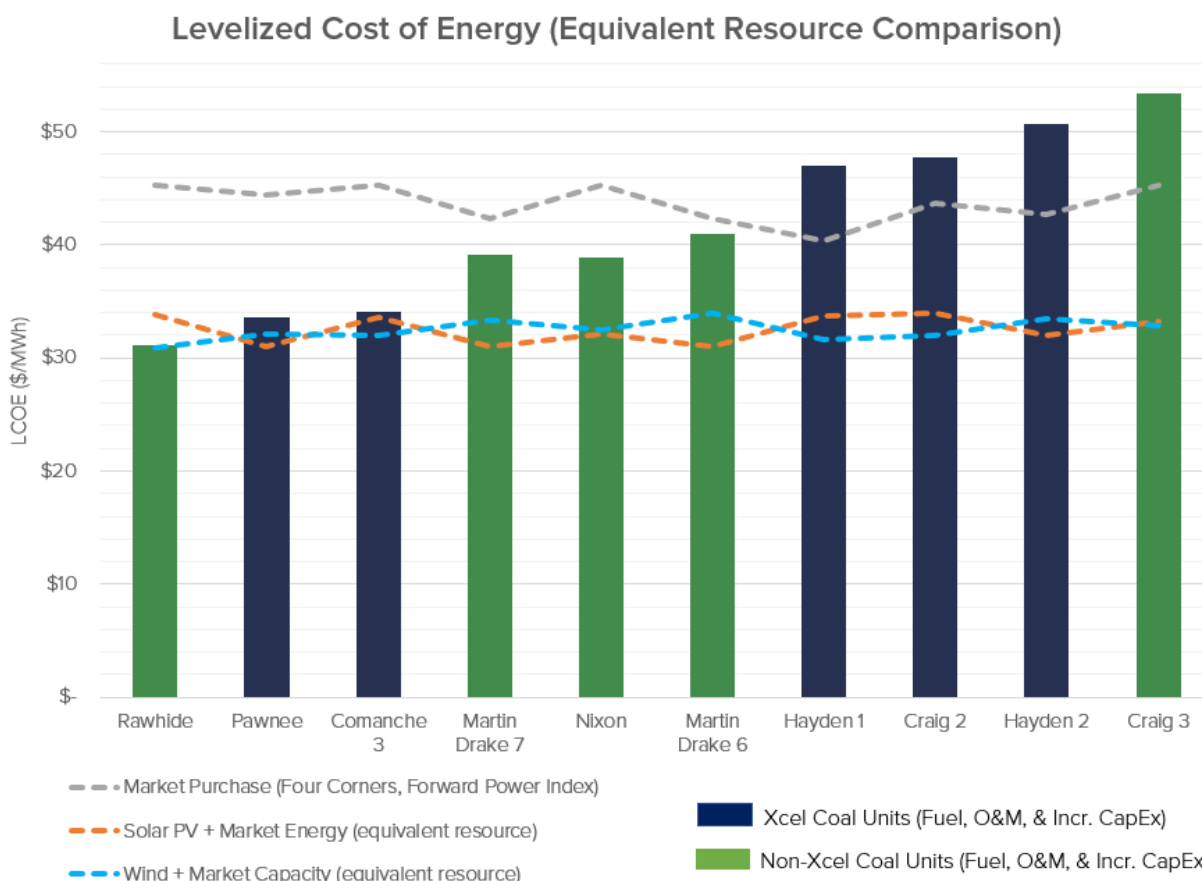


Figure 3. LCOE of Colorado coal units (2023 through 2050 or expected retirement date if sooner) versus replacement resource options. Xcel coal units are in blue. Non-Xcel coal units are in green. Replacement resources include equivalent energy and capacity as the coal units. Replacements include: 1) solar PV with market energy purchases, 2) wind with capacity purchases, and 3) forward market purchases. A 2023 replacement start date was assumed.

In addition to LCOE, we compared the levelized fixed cost (\$/kW-yr) of each coal unit, including fixed O&M and incremental capital costs (excludes fuel and variable O&M). By comparison, the annualized fixed costs for a new combustion turbine (approximately \$61/kW-yr based on Xcel Energy’s 2017 All Source RFP) is lower than all of the coal units except for Martin Drake 6 and 7. Additionally, it is worth noting that the coal units with fixed O&M costs modeled by S&P Global (i.e. Nixon, Rawhide, and Drake) had lower values than those for which reported costs were available. This might suggest that the actual fixed costs for these units are higher than what is assumed in our analysis.

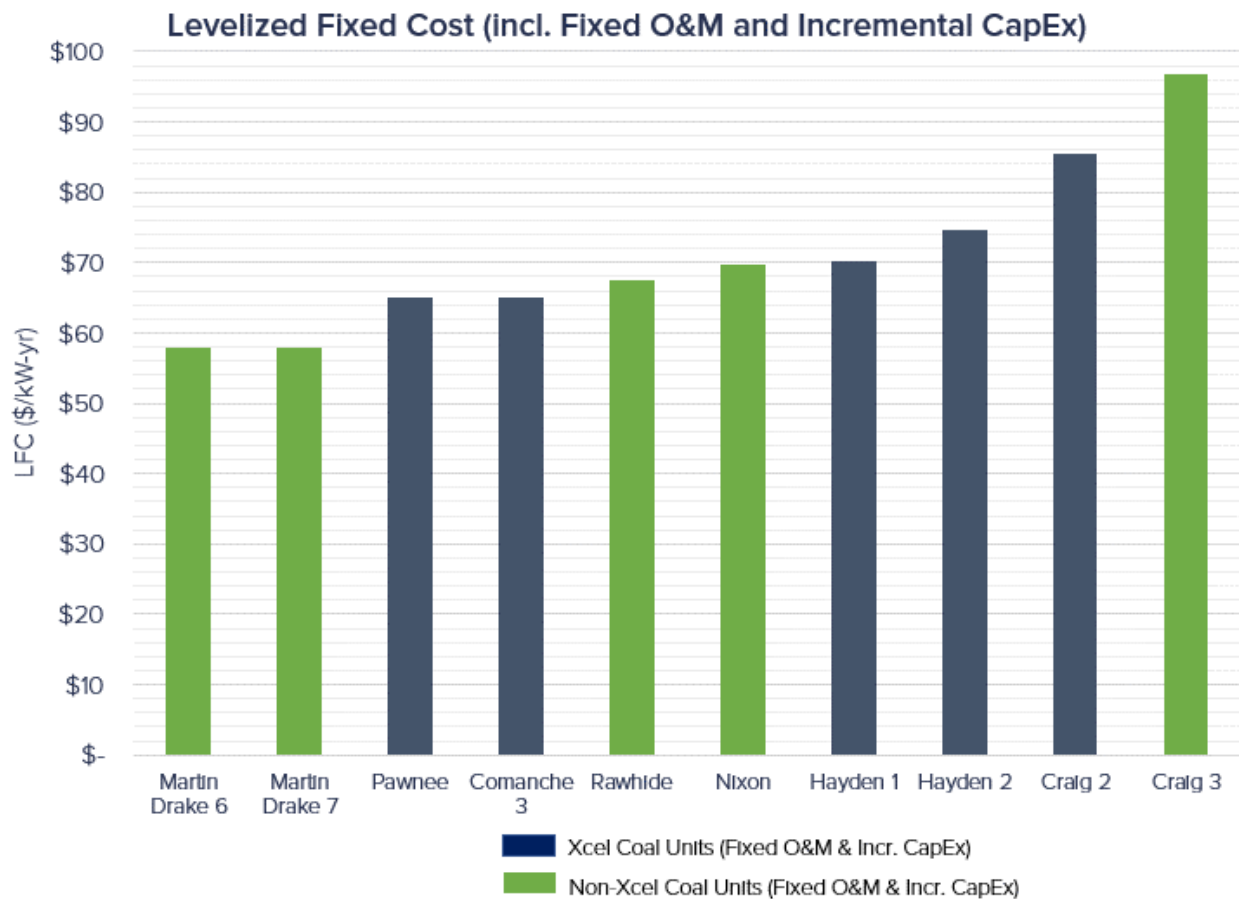


Figure 4. Levelized fixed cost (2019-2050) in 2019\$ comparison for each of the Colorado coal units analyzed. Blue bars correspond to Xcel-owned units, while green bars correspond to non-Xcel-owned units. Non-fuel O&M costs for Martin Drake, Nixon, and Rawhide were based on costs modeled by S&P Global, while the remaining units were based on actual costs as reported via EIA Form 923 and FERC Form 1 (2016-2018 average, escalated at the rate of inflation).

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

In addition to the levelized cost comparisons above, a more detailed replacement analysis was conducted for each of the ten Colorado coal units. In total, these units are projected to cost \$7.2 billion (NPV) in fuel, O&M, and incremental capital expenditures to continue operating through 2050 under a “business as usual” scenario. This does not include any fixed capital costs already committed.

For the Xcel-owned share of these units, the total NPV cost for continued operation from 2023-2050 was estimated to be approximately \$2.6 billion over the units’ remaining operational lifetimes. Of this, a significant share of the costs (~\$2.1 billion) was from Pawnee and Comanche 3, both of which are currently planned to operate past 2040 and in which Xcel owns over 500 MW each. Comanche 3 is the most recently built coal unit (online in 2010) and has a depreciation date of 2070. However, operating costs beyond 2050 were not included in our analysis as explained in the Appendix. While Craig 2 and Hayden 1 & 2 are older and more costly to operate per MWh produced, Xcel owns a

much smaller share of these units, and all three have planned retirement dates that occur sooner, leading to a lower overall projected cost of continued operation for Xcel customers.

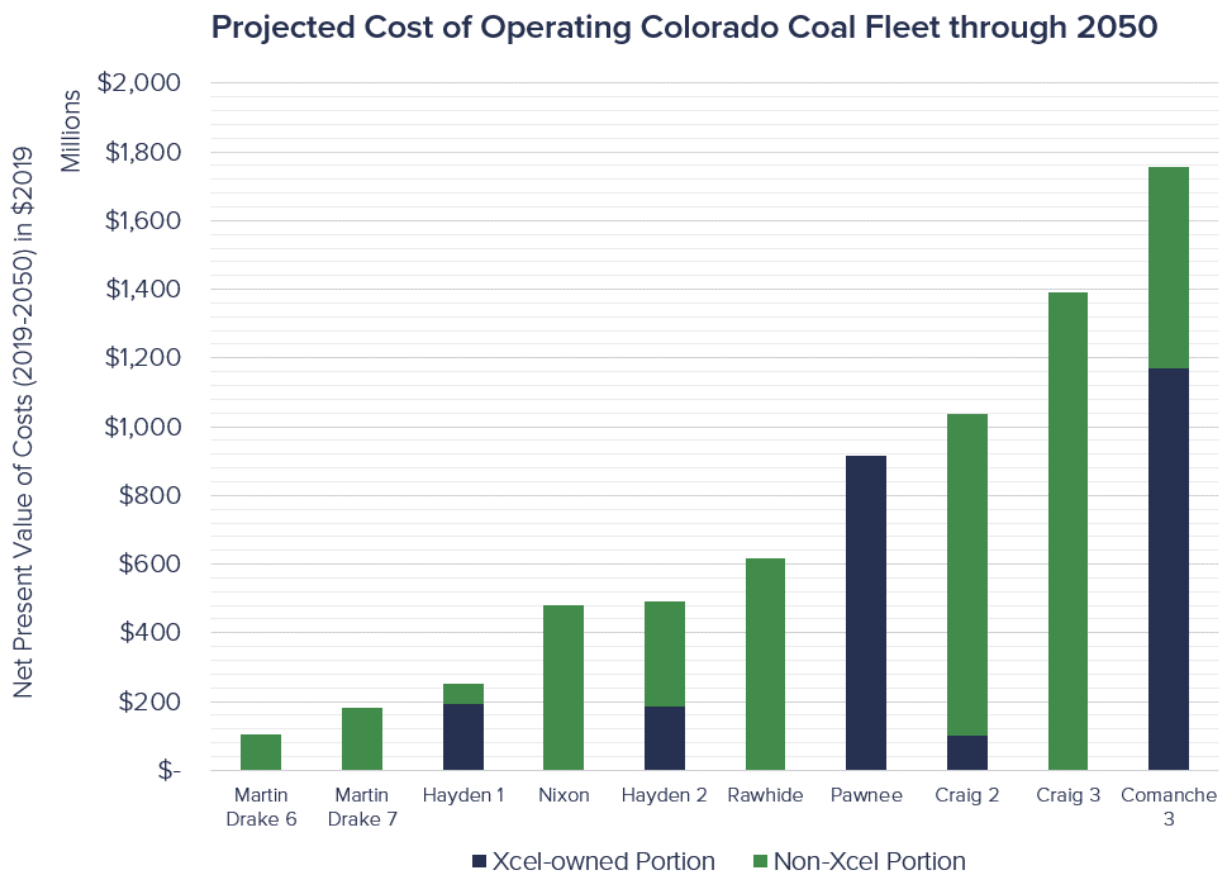


Figure 5. NPV cost (2019-2050) for continued operation of Colorado's coal fleet from 2023 through 2050 (or announced retirement date if sooner). Includes fuel, O&M, and incremental capital costs of coal-fired generation units. Assumes currently announced retirement dates for all units.

## Replacement with Market Purchases

The NPV of incremental costs (or savings) was projected from replacing each coal unit with forward market purchases from Four Corners starting in 2023 (Figure 6). This market purchase “replacement resource” is further characterized in Appendix A.

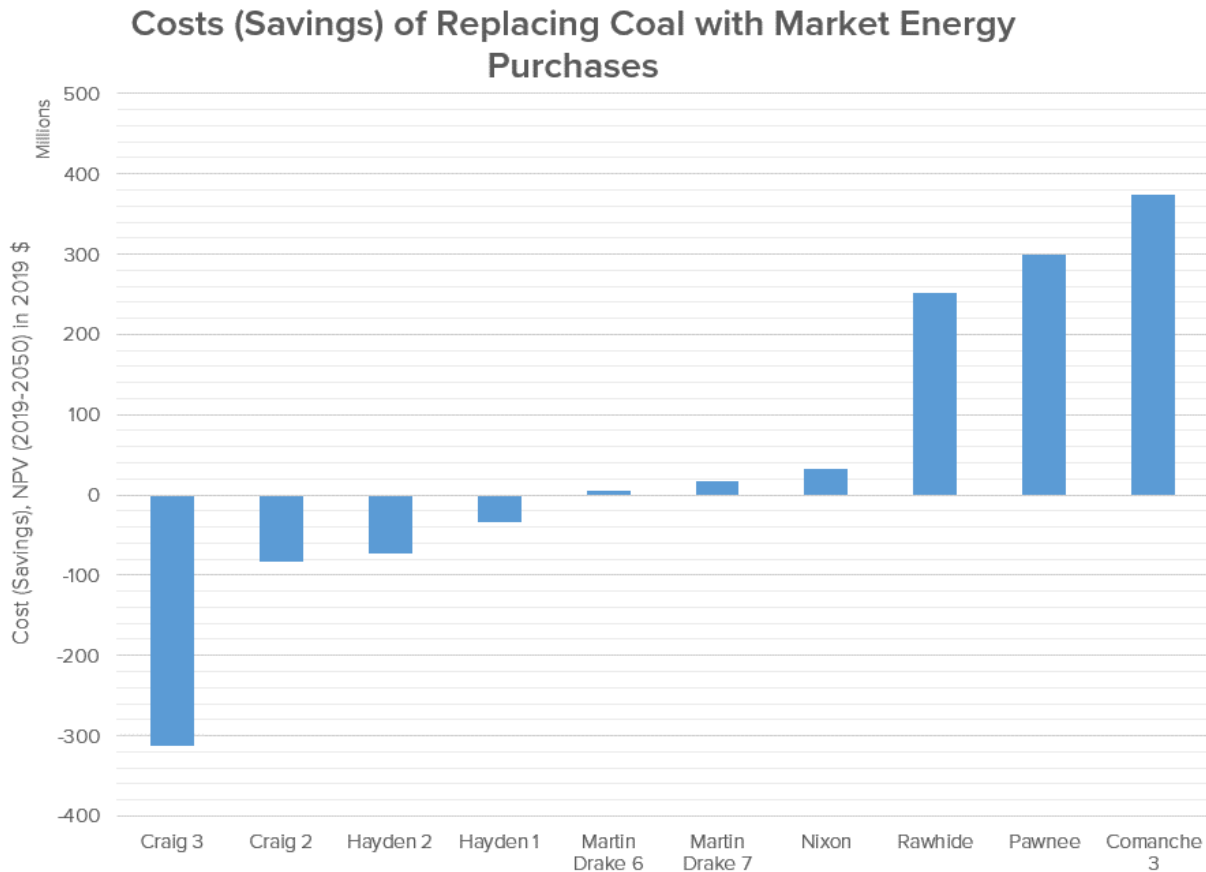


Figure 6. NPV (2019-2050) of total costs (benefits) in 2019\$ from replacing coal generation with Forward Market Purchases from Four Corners starting in 2023. This market purchase “replacement resource” is characterized in Appendix A below. Negative values correspond to potential benefits for the plant owner’s customers. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

Cost savings were observed for replacing both Craig and Hayden units with market purchases starting in 2023 (~\$505 million total reduction, NPV).

This same strategy led to cost increases for the Drake, Nixon, Rawhide, Pawnee and Comanche 3 units (~\$977 million total increase, NPV).

### Replacement with Solar PV

For the second replacement portfolio, the NPV of incremental costs (or savings) was projected from replacing each of Colorado’s coal units with a solar PV resource, combined with market energy purchases, to provide an equivalent resource starting in 2023 (see Figure 7). This solar PV “replacement resource” is further characterized in Appendix A.

For example, replacing the 262 MW Hayden 2 unit with an equivalent-capacity resource requires approximately a 550 MW-ac solar PV resource assuming a 49.5% capacity value.<sup>5</sup> This resource was estimated to yield about 1,222 GWh per year, or about 91% of Hayden 2’s annual output of 1,344

<sup>5</sup> Based on Xcel Energy’s 2016 Electric Resource Plan 120-Day Report: Appendix G – Modeling Assumptions Update (filed June 2018). 49.5% equates to the ELCC value for a tracking solar PV resource located on the Western Slope at 500 MW penetration.

GWh. The remaining 122 GWh were accounted for through market energy purchases so that the solar resource would provide equivalent energy and capacity as the coal unit it is replacing.

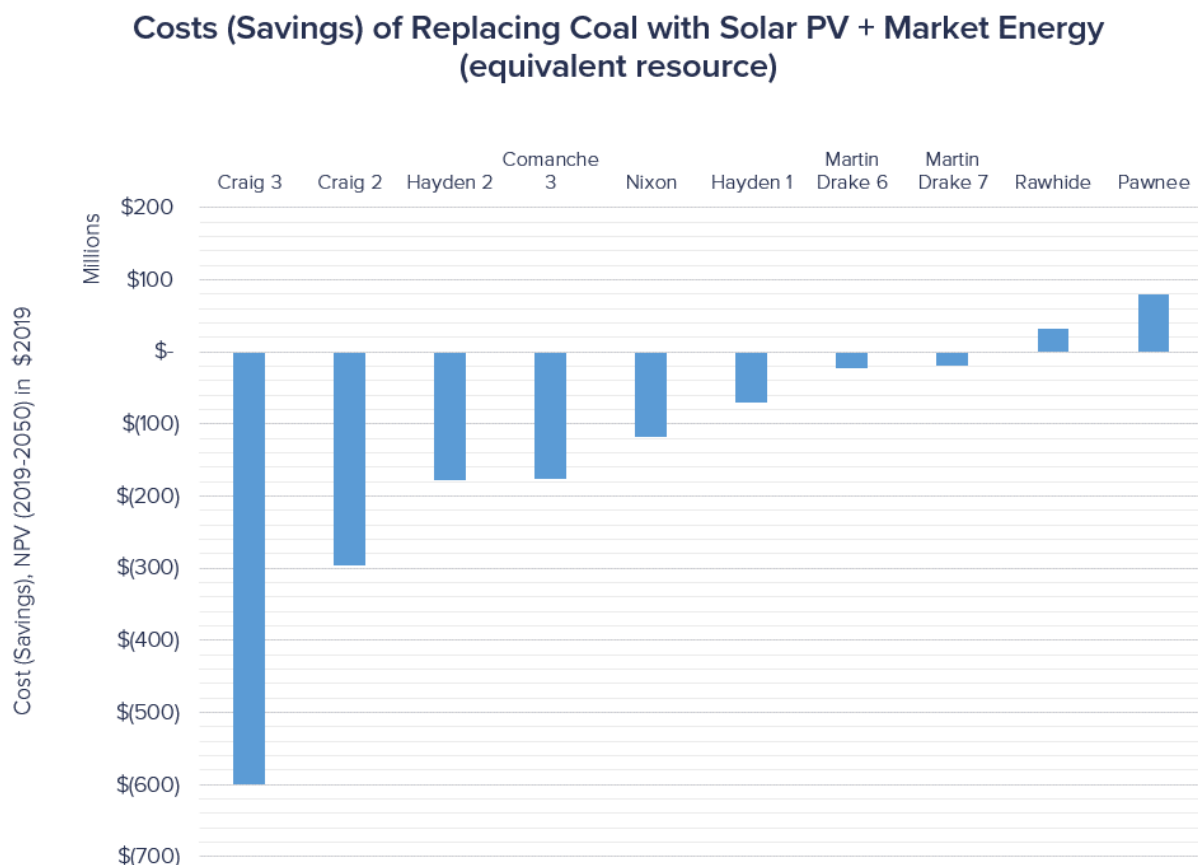


Figure 7. NPV (2019-2050) of total costs (benefits) in 2019\$ from replacing coal generation with a solar PV resource starting in 2023 that provides equivalent energy and capacity. This solar PV “replacement resource” is further characterized in Appendix A. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

Replacing all Colorado coal units with solar PV plus market purchases starting in 2023 would yield approximately \$1.4 billion in savings. Xcel customers would save approximately \$187 million by replacing its ownership share of five coal plants with this option. Only the Rawhide and Pawnee units would not yield savings with the solar replacement option.<sup>6</sup>

## Replacement with Wind

For the third replacement portfolio, the NPV of incremental costs (or savings) was projected from replacing each of Colorado’s coal unit with a wind resource, combined with additional market capacity purchases, to provide an equivalent resource starting in 2023 (see Figure 8). This wind “replacement resource” is further characterized in Appendix A.

<sup>6</sup> In the case of Pawnee this is partly due to the fact that the ELCC value of a solar PV resource located near the plant site (assumes Northern Front Range ELCC value) is significantly lower than other locations in the state. As a result the solar resource must be oversized to provide equivalent capacity value, leading to greater annual energy production than the original coal plant. It is assumed that this excess energy would be curtailed. If this energy were not curtailed, it is possible that the solar PV replacement may be more cost effective than what is illustrated here.

For example, replacing the 1,344 GWh of annual production from the Hayden 2 unit with an equivalent-energy resource requires approximately a 384 MW-ac wind resource (assuming a 40% capacity factor).<sup>7</sup> This resource was estimated to provide about 46 MW in terms of capacity value (based on a 12% wind capacity credit) or about 18% of Hayden 2’s nameplate rating.<sup>8</sup> The remaining 216 MW were accounted for through capacity purchases to provide an equivalent resource in terms of both energy and capacity.

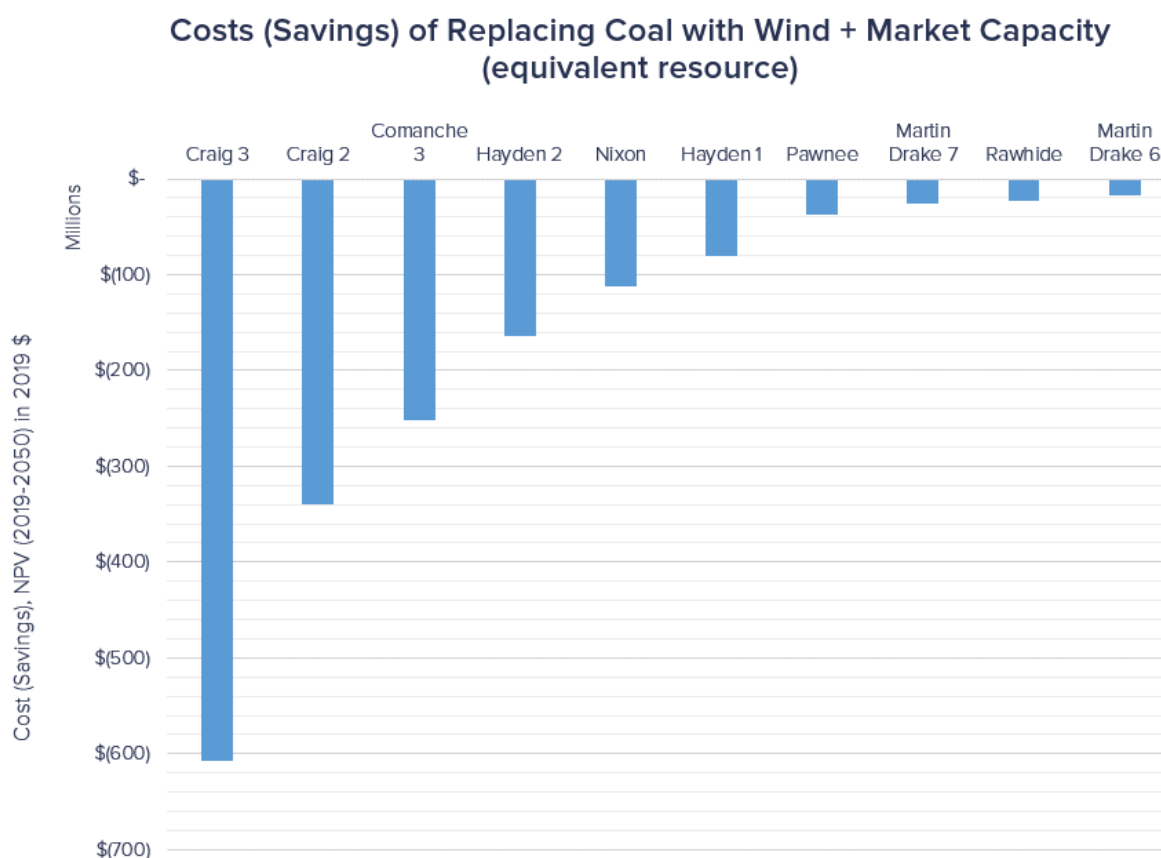


Figure 8. NPV (2019-2050) of total costs (benefits) in 2019\$ from replacing coal generation with a wind resource starting in 2023 that provides equivalent energy and capacity. This wind “replacement resource” is further characterized in Appendix A below. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

We estimate that replacing all ten coal units with wind resources in this fashion could yield approximately \$1.7 billion in total savings (NPV).

Xcel customers could save \$360 million by replacing its share of its five coal units with wind resources in 2023. Specifically, Xcel would save approximately \$33 million by replacing Craig 2,

<sup>7</sup> Recent wind projects sited in Colorado, such as Rush Creek, have had estimated capacity factors of ~44%. While historical capacity factors have been lower for some projects to date, it is anticipated that new wind projects going forward would use modern wind turbine technology would be able to access higher hub heights and thus better quality wind resources. A capacity factor of 40% was assumed to be conservative.

<sup>8</sup> Based on Xcel Energy’s 2016 Electric Resource Plan 120-Day Report: Appendix G – Modeling Assumptions Update (filed June 2018). 12% approximates the ELCC capacity credit for a wind resource based on the average of the three locations provided at a 500 MW penetration level.

\$37 million by replacing Pawnee, \$123 million by replacing both Hayden units, and \$168 million by replacing Comanche 3. It is worth noting that the analysis period only extends to 2050, while Comanche 3 has an expected book life through 2070. Operating costs and benefits beyond 2050 were not included in this analysis as explained in Appendix A.

### **3.4. Social Cost of Carbon Analysis**

In addition to projecting operating costs and capital expenditures of coal-fired generation in Colorado, Strategen conducted an analysis of the societal costs associated with greenhouse gas emissions from the plants. As described in Appendix A, we assumed a social cost of carbon of \$46 per short ton of carbon dioxide emitted in 2020, which is the minimum price specified by SB 19-236 for use in energy resource planning. In accordance with the requirements of SB 19-236, this analysis escalated the SCC annually based on an escalation rate schedule set by the Interagency Working Group on Social Cost of Greenhouse Gases.

Requiring coal plants to internalize the cost of carbon pollution through the application of a social cost of carbon increased the total costs for Colorado's coal-fired generation units, making all of them less economic than any of the replacement options. Figure 9 compares the cost of energy for each coal unit with alternatives on a levelized basis with the addition of the social cost of carbon (grey bar). For market energy purchases (including those associated with the solar PV replacement resource), a social cost of carbon was also applied that equates to the emissions associated with a natural gas combined cycle unit.<sup>9</sup>

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<sup>9</sup> 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 assumes a heat rate of 7,649 BTU/kWh consistent with the following: [https://www.eia.gov/electricity/annual/html/epa\\_08\\_02.html](https://www.eia.gov/electricity/annual/html/epa_08_02.html)

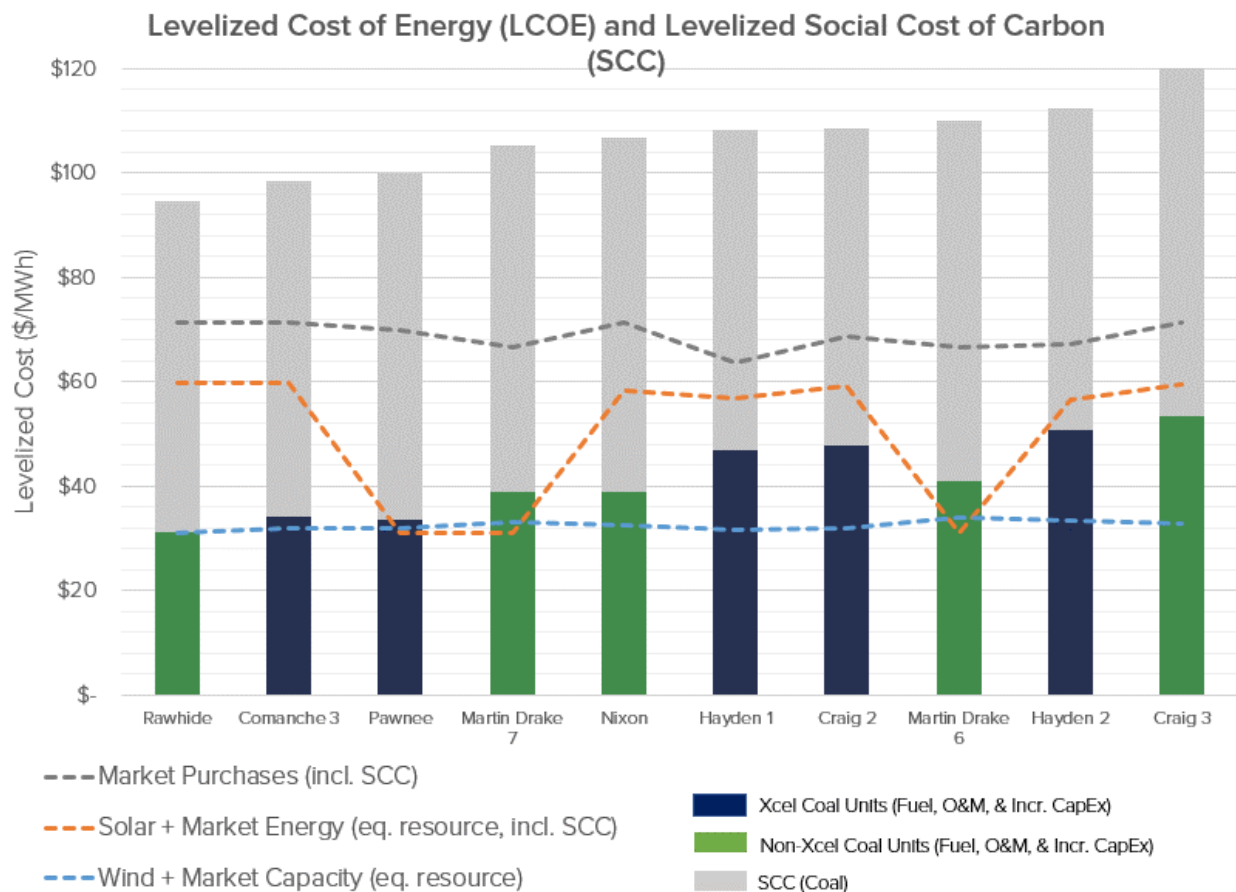


Figure 9. LCOE of all Colorado coal-fired generation units with added levelized social cost of carbon, all in 2019\$, is compared to costs for solar PV, wind, and market purchase replacement alternatives. The colored bars represent the operating costs (and incremental capital costs) of the plant, while the grey bars represent the social cost of carbon.

The NPV analysis was conducted for the wind and solar replacement resources with the inclusion of the SCC. In some cases where planned retirements are decades away, adding the SCC nearly quadrupled the NPV costs of certain coal units. For certain coal units such as Comanche 3, Craig 3, and Pawnee, the costs grew especially high because of their longer lifetimes and large size under a business-as-usual scenario.

Figure 10 illustrates the total societal costs and benefits through 2050 (NPV) of replacing all ten coal units with the solar PV replacement option in 2023 once the SCC was factored in. The total net benefits of this scenario were found to be \$17.7 billion. Xcel Energy's portion of these savings equates to \$7 billion. Including the savings from avoided O&M costs and incremental capital expenditures brings these totals to \$19.1 billion and \$7.2 billion respectively.

### Societal Costs (Benefits) from Replacing Coal-fired Generation with a Solar PV Resource (including Social Cost of Carbon)

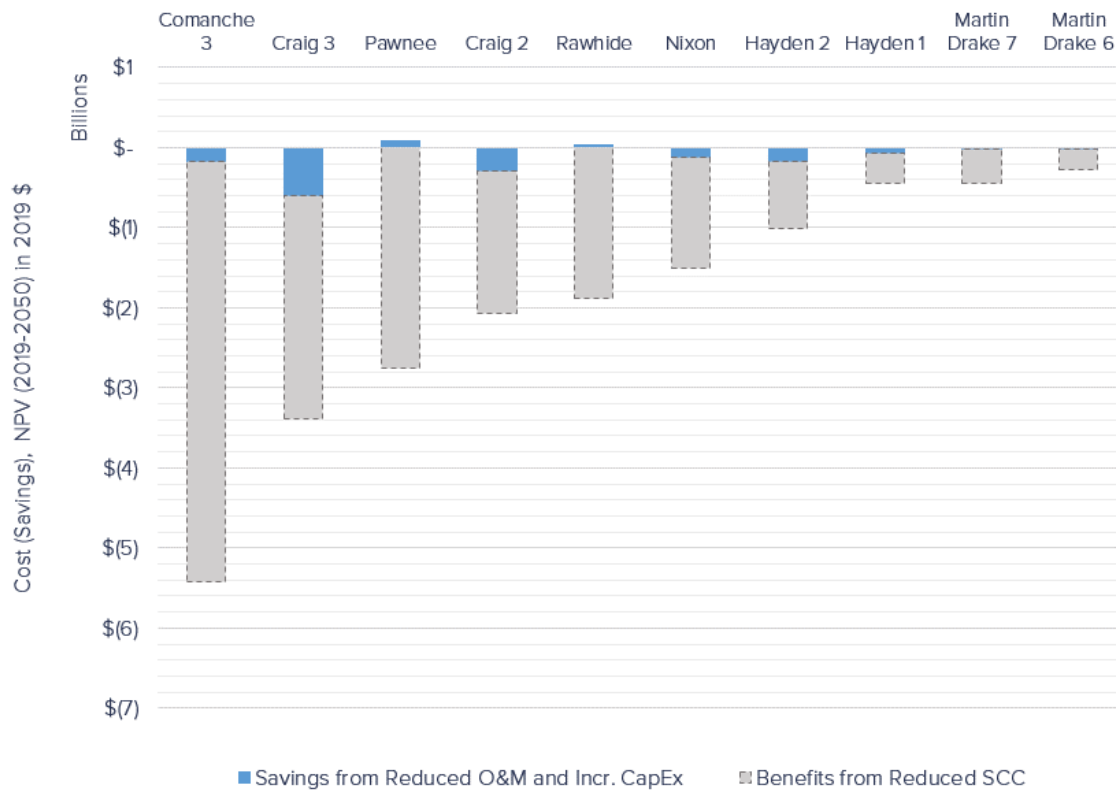


Figure 10. Savings in NPV from retiring Colorado coal generation units in 2023 compared to the solar PV replacement resource, when factoring in SCC. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

Figure 11 illustrates the total societal costs and benefits through 2050 (NPV) of replacing all ten coal units with the wind replacement option in 2023 once the SCC was factored in. The total net benefits of this scenario are \$18.7 billion. Xcel Energy's portion of these savings is \$7.3 billion. Including the savings from avoided O&M costs and incremental capital expenditures brings these totals to \$20.4 billion and \$7.7 billion respectively.

### Societal Costs (Benefits) from Replacing Coal-fired Generation with a Wind Resource (including Social Cost of Carbon)

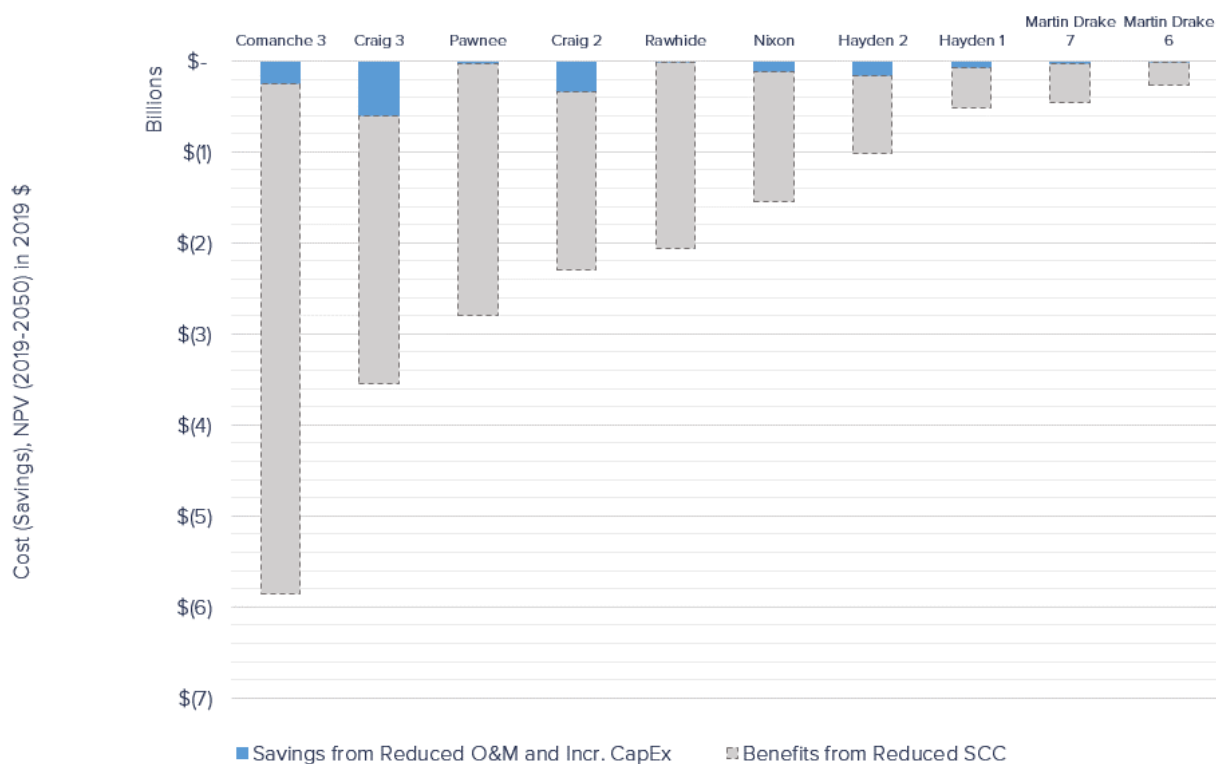


Figure 11. Savings in NPV from retiring Colorado coal generation units in 2023 compared to the wind replacement, when factoring in SCC. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

## 3.5. Securitization Analysis

For the five coal units owned by Xcel, an analysis was conducted to determine additional ratepayer benefits that might be achieved through the securitization of remaining plant capital costs. The total capital cost necessary to enable retirement for each coal unit was assumed to be financed with a AAA-rated bond amortized over a period of 20 years starting in 2023.<sup>10</sup> Due to the low financing costs for such an instrument, ratepayer savings can be realized compared to a “business as usual” scenario under which a higher rate of return is applied to the undepreciated portion of the existing coal asset.

The total ratepayer benefits (NPV) are illustrated below for both a wind PPA replacement and a solar PPA replacement of the Xcel-owned portion of the five units. Each chart includes both the operational and incremental capital cost savings estimated in Section 3.3 plus the additional savings from securitization.

In total, we estimate that Xcel Energy customers could save \$467 million (NPV) from securitizing the remaining costs of each coal asset upon replacement when compared to business as usual. This is in addition to the operating and incremental capital cost savings of \$187 million for a solar replacement option and \$360 million for a wind replacement option. The additional ratepayer benefit

<sup>10</sup> Total retirement costs were assumed to be comprised of undepreciated coal unit plant balances (not including common costs) plus the cost of removal (net of salvage value).

of securitization is illustrated below for both the solar PV and wind replacement options (Figure 12 and Figure 13).

The authorizing legislation for securitization (SB 19-236) signed on May 30, 2019, included provisions pertaining to transition assistance for communities and workers affected by plant closures. To the extent that a portion of the ratepayer savings from securitization is used for transition assistance, this would reduce the total ratepayer savings available to Xcel customers that are calculated below.

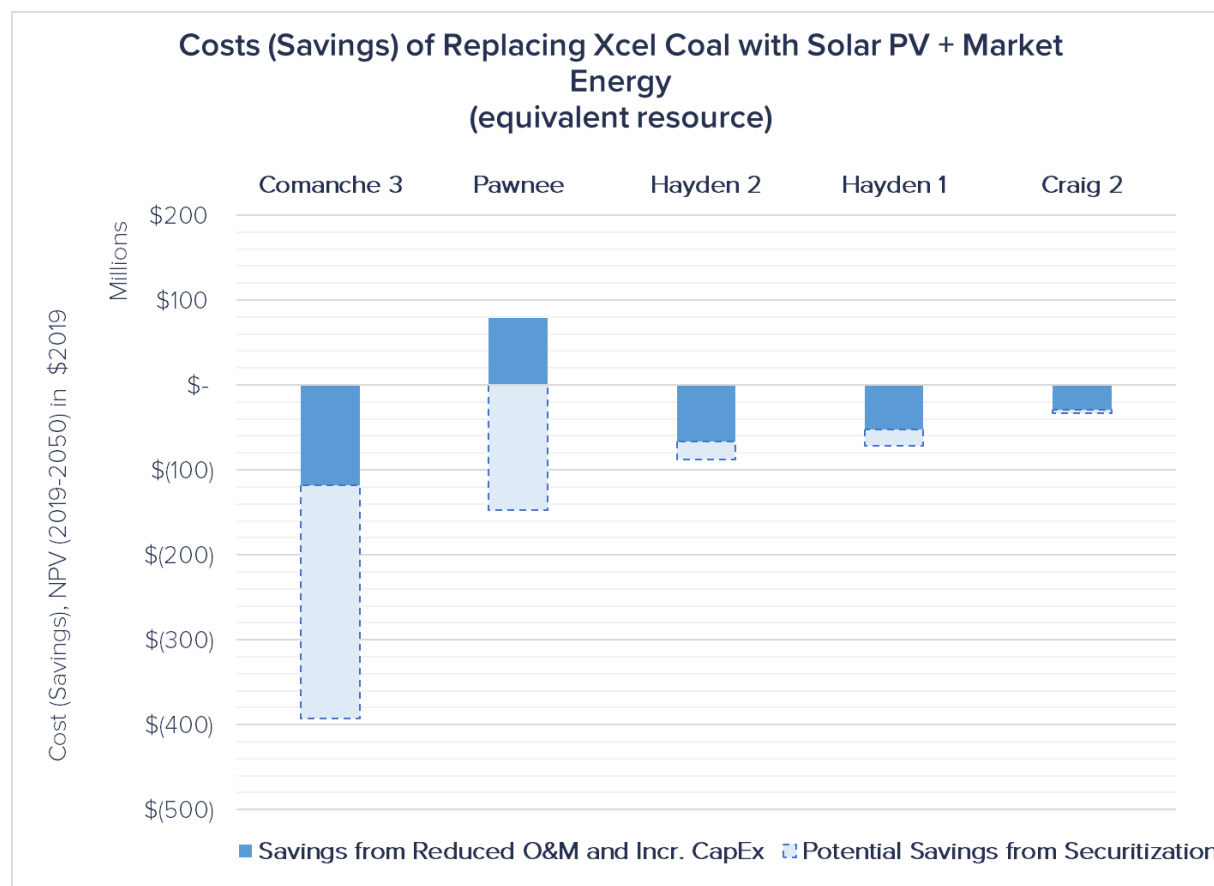


Figure 12. Costs (savings) to Xcel energy customers from replacing coal assets with a solar PV replacement resource in 2023, plus securitization of the existing coal retirement costs. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

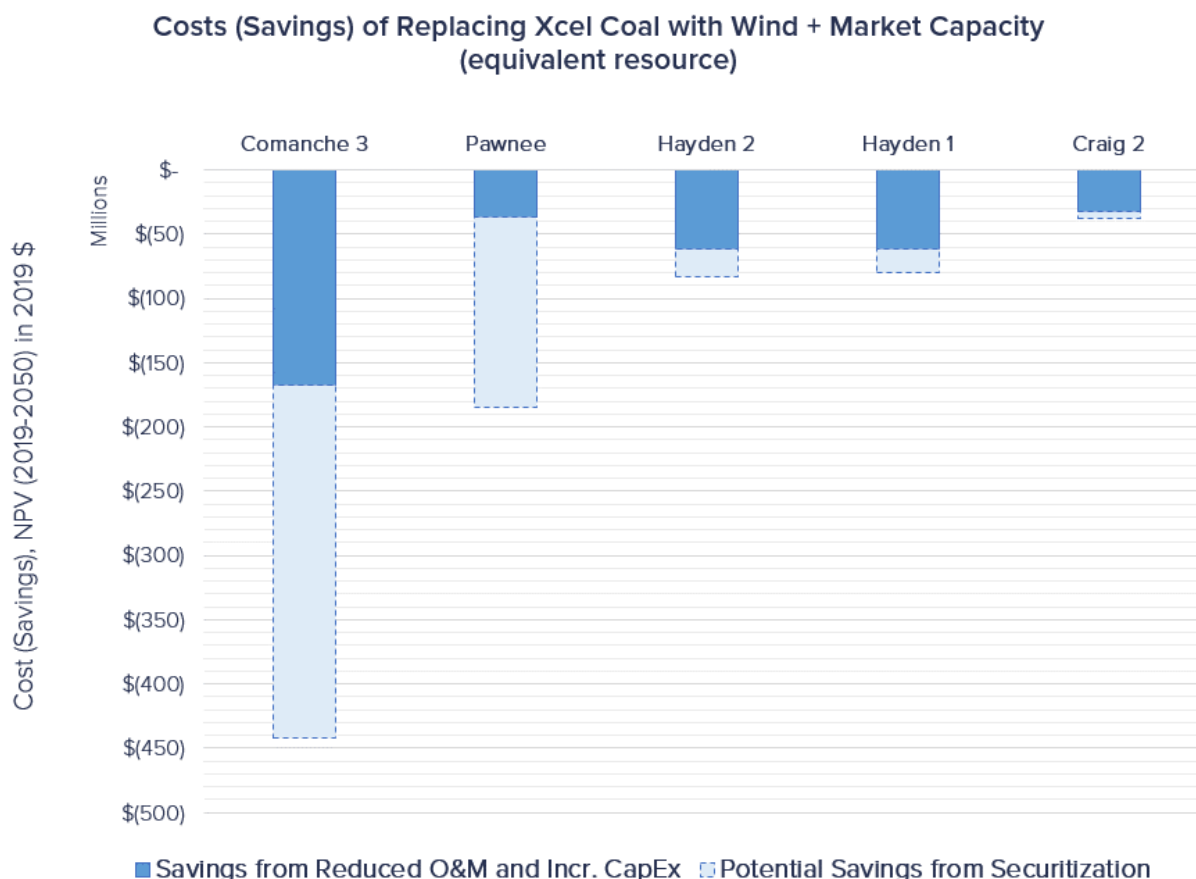


Figure 13. Costs (savings) to Xcel energy customers from replacing coal assets with a solar PV replacement resource in 2023, plus securitization of the existing coal retirement costs. The period of analysis starts earlier than 2023 to reflect reduced capital expenditures before retirement.

## 4. Key Findings & Conclusions

Colorado utilities and Xcel in particular can realize savings for their customers through an orderly retirement of their coal fleet and replacement with clean energy alternatives. The recent legislative session produced a raft of legislation, providing a new tool in securitization to help ease the transition to clean energy, while the social cost of carbon requirement offers a new lens to assess the cost of coal-fired power on Coloradans. Even without these changes, however, it is clear that coal is no longer an economic resource in most cases for Xcel as well as for other utilities in Colorado.

Based on our analysis of operating and incremental capital costs, the highest-cost coal-fired units in Colorado (on an LCOE basis) are those at the Craig and Hayden power plants. In general, the oldest coal-fired generation units analyzed in this study had a higher cost per unit of output (e.g., LCOE) compared to more recently constructed units. However, the more recently constructed units generally had a higher overall cost going forward (on an NPV basis) due to their longer remaining service lives. For example, the older Craig and Hayden plants proved most expensive to operate on an LCOE basis, while Comanche 3 had by far the largest NPV costs of the Colorado coal units. When replacement options were evaluated on an equivalent capacity basis, the results of this analysis did

not change significantly when compared to an energy-only analysis. That points to the potential of renewables-plus-market purchases to replace coal-fired energy capacity without significantly adding to costs.

On an LCOE basis, the older Hayden and Craig plants are largely uneconomic when compared to any of the three replacement options considered here (market purchases, solar-plus-market purchases and wind generation). The remaining units appear to remain economical when compared to the market purchase replacement. However, all the units are uneconomic when compared to a wind replacement resource option, and all but two units (Rawhide and Pawnee) are uneconomic when compared to a solar PV replacement option. When the social cost of carbon was accounted for, even the coal units with the lowest operating costs (e.g. Rawhide) were found to be uneconomic and their continued operation led to large costs from a societal perspective relative to a replacement resource.

Given the phaseout of the federal Production Tax Credit and phasedown of the Investment Tax Credit, the timeline for starting construction of wind and solar resources will impact the resources' cost-competitiveness. Actions taken to secure replacement resources now could lead to significantly increased benefits relative to resources procured in future years.

For example, the cost of energy per MWh for wind depends significantly on whether the resource receives a higher level of federal Production Tax Credit (e.g. 60% PTC for commencing construction in 2018) or a lower amount if construction commences at a later date (e.g. 0% for construction commencing in 2021). A resource receiving a 60% PTC versus no PTC could result in a 25 percent price differential.

Finally, as described earlier, this analysis finds that wind generation in Colorado has the greatest potential to produce energy cheaper than coal-fired power, even after including market purchases to provide equivalent capacity value.

Table 3. Summary results: benefits of replacing coal units with a wind replacement resource by 2023. Each column represents a distinct set of benefits and not a cumulative total. Results are in 2019\$ (NPV 2019-2050)

Plant – Unit	NPV – Ratepayer Benefits (Costs) from Operations, Maintenance & Incremental Capital Expenditures	NPV – Additional Societal Benefits from Reduced CO <sub>2</sub> Emissions	NPV – Additional Ratepayer Benefits from Securitization (Xcel Energy share only)
Comanche 3	\$251,558,199	\$5,601,742,148	\$274,545,642
Craig 3	\$608,173,801	\$2,940,232,017	\$-
Pawnee	\$36,901,952	\$2,761,587,276	\$147,822,287
Craig 2	\$339,262,927	\$1,961,102,353	\$4,899,331
Rawhide	\$22,868,059	\$2,035,789,053	\$-
Nixon	\$112,730,093	\$1,426,431,873	\$-
Hayden 2	\$164,549,501	\$857,744,870	\$21,396,951
Hayden 1	\$80,928,221	\$432,196,847	\$18,636,352
Martin Drake 7	\$25,608,254	\$430,192,535	\$-
Martin Drake 6	\$16,908,479	\$245,556,463	\$-
<b>Total</b>	<b>\$1,659,489,486</b>	<b>\$18,692,575,434</b>	<b>\$467,300,563</b>

Table 4. Summary results: benefits of replacing coal units with a solar PV replacement resource by 2023. Each column represents a distinct set of benefits and not a cumulative total. Results are in 2019\$ (NPV 2019-2050)

Plant – Unit	NPV – Ratepayer Benefits (Costs) from Operations, Maintenance & Incremental Capital Expenditures	NPV – Additional Societal Benefits from Reduced CO <sub>2</sub> Emissions	NPV – Additional Ratepayer Benefits from Securitization Xcel Energy share only
Comanche 3	\$177,071,596	\$5,250,840,440	\$274,545,642
Craig 3	\$599,281,518	\$2,784,225,301	\$-
Pawnee	(\$78,660,284)	\$2,761,587,276	\$147,822,287
Craig 2	\$296,612,762	\$1,770,138,323	\$4,899,331
Rawhide	(\$31,878,772)	\$1,879,523,413	\$-
Nixon	\$117,534,587	\$1,389,386,118	\$-
Hayden 2	\$178,219,074	\$826,879,632	\$21,396,951
Hayden 1	\$69,660,450	\$384,025,979	\$18,636,352
Martin Drake 7	\$19,967,901	\$430,192,535	\$-
Martin Drake 6	\$22,762,925	\$245,556,463	\$-
<b>Total</b>	<b>\$1,370,571,756</b>	<b>\$17,722,355,481</b>	<b>\$467,300,563</b>



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## Appendix A: Methodology

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### A.1 Coal Fleet Cash Flow Analysis

Strategen conducted a discounted cash flow analysis for the Colorado coal units identified above 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. This was supplemented by unit-specific data from other sources, including regulatory filings available via the Colorado Public Utilities Commission.

For each coal unit, the cost elements examined 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 Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G).<sup>11</sup> While the analysis extended through year 2050, we assumed unit retirements would occur based on currently announced retirement dates, except as described below in the replacement analyses. For some plants, no retirement date has been announced and it was thus assumed the plant would operate through 2050. In the case of Comanche 3, the currently planned retirement date is 2070. However, for the purposes of our analysis we did not include any incremental operating costs beyond 2050.<sup>12</sup> This was done both for consistency with other plants in the analysis and to match Xcel's commitment to achieve 100% carbon free electricity by 2050. 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. Non-fuel O&M costs were estimated based on plant-level data collected from S&P Global (2016-2018 average) and escalated at an assumed annual rate of inflation (2.0%). For the Comanche, Craig, Hayden, and Pawnee plants these costs are based on data reported in EIA Form 923 and FERC Form 1. For the Drake, Rawhide, and Nixon plants, directly reported O&M cost data were unavailable, and thus S&P-modeled O&M cost estimates were used.<sup>13</sup> Fuel costs were based on 2016-2018 average reported costs for each plant and escalated each year at a rate consistent with Xcel Energy's most recent coal price forecast.

Dismantling costs for Comanche 3, Craig 2, Hayden 1 & 2, and Pawnee were based on documents filed by Xcel with the Colorado Public Utilities Commission. A \$ per MW average of these Xcel units was calculated and used to estimate the dismantling costs of the non-Xcel units.

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.

### A.2 Replacement Analysis

As an initial screen, the LCOE of the coal plants was compared to the LCOE of a wind resource, a solar PV resource, and a market purchase resource (see Figure 2). A more detailed "replacement resource" analysis was also conducted as described below.

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<sup>11</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>12</sup> As such, the avoided fuel and O&M costs for Comanche 3 are likely conservative.

<sup>13</sup> As S&P notes in its database, "In the absence of current-year filings, S&P Global Market Intelligence utilizes regression analysis to generate cost estimates. Inputs to the model are taken from the EIA 923, FERC Form 1 and CEMS." Notably, at plants where both reported and S&P-modeled cost estimates were available, the modeled estimates were lower.

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 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 peak capacity (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.

## Forward Market Purchases

The cost of a market purchase replacement resource option was estimated based on the Four Corners Forward Power Index published by OTC Global Holdings (as reported by S&P Global) as of April 2019. Monthly on-peak and off-peak forward power prices were available through March 2029 and were used to determine annual averages in \$/MWh. For the remaining periods (April 2029–December 2050), power prices were assumed to escalate at a rate of 2% annually. It was assumed that 50% of the market purchase replacement power was on-peak and 50% was off-peak.

## Solar PV Replacement

A solar PV replacement option was considered. The capacity value of the solar PV system was assumed to be equal to the ELCC capacity credit for a single-axis tracking solar PV system, consistent with those provided in Xcel’s 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G).<sup>14</sup>

The cost of a solar PV system was estimated assuming a fixed PPA price of \$30.96/MWh. This price was based on Xcel’s 2017 All-Source RFP, which received a median bid price of \$30.96/MWh for solar PV resources.<sup>15</sup> We assume that the solar replacement resource would commence construction in 2019 and enter service on December 31, 2022, and thus be eligible for the full 30% Investment Tax Credit (ITC).<sup>16</sup>

For comparison, the cost of a solar PV system was recently estimated by PacifiCorp as part of its 2019 IRP process and reported in their November 2018 Supply-Side Resource Table.<sup>17</sup> PacifiCorp estimated the cost for a similar solar system located in Utah (which has access to a solar resource similar to Southeastern Colorado) to be \$31.31/MWh assuming a 2021 online date.

The annual MWh output of each solar PV system in Colorado was estimated using NREL’s System Advisor Model based on a system being constructed near the location of each retired coal plant. When sized to provide equivalent capacity value as the coal resource, a solar PV resource does not always provide sufficient energy to match the coal plant’s output. As such, additional market energy purchases were also assumed to ensure MWh were being provided equal to the coal unit’s energy

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<sup>14</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>15</sup> It was assumed that there would solar PV technology cost declines over this period of 2%/yr, but that these would be offset by the inflation rate of 2%.

<sup>16</sup> IRS Notice 2018-59

<sup>17</sup> Assumes a capital cost of solar PV equal to \$1,268 /kW.

[http://www.pacificorp.com/content/dam/pacificorp/doc/Energy\\_Sources/Integrated\\_Resource\\_Plan/2019\\_IRP/Table\\_6.1-6.3-TRC\\_for\\_Supply-Side\\_Resource\\_Options\\_19\\_IRP\\_for\\_PDF.pdf](http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/Table_6.1-6.3-TRC_for_Supply-Side_Resource_Options_19_IRP_for_PDF.pdf)

output. The cost of these market purchases was estimated using the same method as described above. In cases where the energy of the solar PV resource exceeded the coal unit, it was conservatively assumed the excess energy would be curtailed.

## Wind Replacement

A wind replacement option was also considered. The wind resource was assumed to have a capacity factor of 40%.<sup>18</sup> The cost of the wind generation was estimated assuming an average fixed PPA price of \$26.41/MWh. This price was initially based on the results of Xcel's 2017 All-Source RFP which revealed a median wind bid price of \$19.30/MWh. The price was adjusted upwards by \$7.11/MWh, based on the assumption that the 2017 median bid prices reflect projects commencing construction in 2017, thus qualifying for an 80% Production Tax Credit (PTC), and that 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.<sup>19</sup> Taking a conservative approach, we assumed that half of new wind resources entering service by December 2022 would have a commence construction date of 2018 (thus qualifying for a 60% PTC) and that half would have a commence construction date of 2019 (thus qualifying for a 40% PTC).

For comparison, PacifiCorp estimated a Wyoming wind resource with a similar capacity factor being placed into service in 2023 would have a cost of \$26.41/MWh.<sup>20</sup>

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 the effective load-carrying capacity (ELCC) credit, consistent with those provided by Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G).<sup>21</sup> Additional capacity was purchased at an assumed cost of \$36.06/kW-yr in 2019. This reflects an assumed blended average of \$11.16/kW-yr for short-term market purchases and \$60.96/kW-yr cost for a new combustion turbine.<sup>22</sup> The capacity cost was assumed to escalate at the rate of inflation.

## Caveats:

The analysis did not factor in the potential costs of building transmission infrastructure for renewable energy. Replacement energy needs were estimated on an annual basis and thus might not capture other costs or benefits that may arise from an hourly or sub-hourly dispatch analysis, including renewable integration costs.

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<sup>18</sup> For comparison, Xcel's Rush Creek wind project has an estimated capacity factor of 43.6%. While this exceeds the capacity factors for other historical wind projects in CO, it is expected that modern wind turbines will be able to access higher hub heights consistent with a capacity factor of 40% or greater. To be conservative we assume wind projects have a capacity factor of 40%. <https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/051716-xcel-plans-600-mw-colorado-wind-farm-expects-project-online-by-nov-2018>

<sup>19</sup> <https://www.windpowerengineering.com/business-news-projects/more-than-61-gw-of-u-s-wind-turbine-equipment-has-qualified-for-the-ptc-since-2016/>

<sup>20</sup> Assumes a capital cost of \$1,301/kW.

<sup>21</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>22</sup> According to Xcel's most recent ERP assumptions, capacity credit was valued at \$2.79/kW-mo for 4 months (or \$11.16/kW-yr) in the near term, and in the long-term at the cost of a generic combustion turbine. Recent RFP median bid prices for a combustion turbine were \$5.08/kW-mo (or \$60.96/kW-yr).

Fuel supplies for at least two of the coal plants examined, Craig and Hayden, are currently subject to Coal Supply Agreement, ending in 2020 and 2027 respectively. While Strategen is not privy to the terms of these contracts, it is possible that they include “take or pay” provisions that are common to many Coal Supply Agreements. If such provisions exist, we expect this would yield a modest reduction in the benefits of replacing the Hayden units prior to 2027 versus the BAU case.

### A.3 Social Cost of Carbon

On May 30, 2019, Governor Polis signed into law the Sunset Public Utilities Commission Act, which, among other things, requires that “an electric public utility subject to commission jurisdiction to consider the cost of carbon dioxide emissions ... when determining the cost, benefit, or net present value of any plan or proposal submitted.”<sup>23</sup> The requirement pertains to utility electric retail services providers as well as to “electric resource plans or any utility plan or application that considers or proposes the acquisition of new electric generating resources or the retirement of existing utility generation.”<sup>24</sup> The requirement also applies to “a plan or application for transportation electrification or other forms of beneficial electrification.”<sup>25</sup>

To understand the impact of this new legislation, the cash flow analysis considered a scenario using the statute’s minimum value for the social cost of carbon, *i.e.*, \$46 per short ton of carbon dioxide emitted in 2020. As the law specifies, the SCC should escalate according to “the central value escalation rates established in the technical support document” of “the most recent assessment of the social cost of carbon dioxide developed by the federal government.” The legislation allows the Commission, now, or at a later date, to require the use of a higher price for the social cost of carbon. Thus, this analysis is a conservative estimate of the impacts of the use of the social cost of carbon.

As such, an annual escalation rate was applied as follows:

- 2.1% annually from 2020 to 2030;
- 1.9% from 2030 to 2040; and
- 1.6% from 2040 to 2050.

The present value of the SCC component was calculated using a 3% discount rate, consistent with the legislation which specifies that “the commission shall use the same discount rate as that used to develop the federal social cost of carbon dioxide, as set forth in the technical support document.”<sup>26</sup>

### A.4 Securitization Analysis

In addition to the legislative changes described above, SB 19-236 also included provisions that authorize utilities to apply for a financing order from the PUC to implement securitization.

Accelerated retirement of an existing power plant can raise concerns over “stranded costs” and may require steps to ensure that plant’s original investors (e.g. utility shareholders) are made whole even when the plant is no longer considered “used and useful.” Securitization is one tool that can accomplish this. It allows investor-owned utilities (such as Xcel Energy) to refinance the remaining capital costs of the existing power plant while also achieving a lower rate of return. This is

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<sup>23</sup> SB 19-236, § 13, adding § 40-3.2-106(1), C.R.S.

<sup>24</sup> *Id.*, adding § 40-3.2-106(1)(a), C.R.S.

<sup>25</sup> *Id.*, adding § 40-3.2-106(1)(d), C.R.S.

<sup>26</sup> *Id.*, adding § 40-3.2-106(4), C.R.S.

generally 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). Ratepayer-backed bonds are generally considered to be a safe investment and can carry a AAA rating and an interest rate typically in the 3-4 percent range, compared to the typically higher cost of capital generally used in utility financing.

Strategen estimated the potential benefits securitization could yield for Xcel customers if applied to each of five Xcel coal units considered in this analysis upon retirement. These savings derive from the fact that Xcel customers currently pay for the ongoing financing cost of existing coal assets at Xcel's authorized rate of return. Under a securitization scenario associated with accelerated retirement, these financing costs could be replaced with a lower-cost bond option. For this, we assumed a financing cost of 3.5%, which approximates the interest rate for a AAA-rated bond.

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 (including both plant life depreciation and cost of removal), and annual return on net plant (plus a gross up for taxes). Starting plant balances, depreciation reserve balances, and depreciation expenses for each coal unit were based on Xcel's recent settlement in Docket Number 16A-0231E.<sup>27</sup> The return on net plant under the BAU case was based on Xcel's weighted average cost of capital (WACC).

In the case of Comanche 3, the capital costs under BAU extended through 2070, which is beyond the analysis period. As such the residual cost of the asset was estimated and included in the calculation of net present value.

For the securitization scenario, a 20-year bond was assumed with a starting value equal to the net plant balance plus the estimated cost of removal (net of salvage value) in the year 2023. Ratepayer costs were assumed to be equal to the principal and interest of the bond in each year of its tenor.

The net present value (NPV) was calculated for both cases and the difference was estimated to be the overall benefit to Xcel customers from securitization. The global discount rate of 6.78% was also used to calculate the present value of ratepayer benefits from securitization.

### **Caveats:**

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 associate 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.

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## **Appendix B: Key Assumptions and Data Sources**

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<sup>27</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)

### Global Assumptions:

Assumption/Input	Value	Source & Description
Discount Rate	6.78%	Discount rate for Xcel Energy consistent with Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G). <sup>28</sup>
Inflation Rate	2.0%	Inflation rate for Xcel Energy consistent with Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G). <sup>29</sup>

### 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 were assumed in 2019 and escalated at a rate consistent with coal price forecast used in Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G).
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 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. Average of 2016-2018 values were assumed in 2019 and escalated at inflation rate for subsequent years.
Incremental Capital Costs	\$20-27/kW-yr	Based on EIA NEMS model. <sup>30</sup> \$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. <sup>31</sup> For non-Xcel 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
Retirement Date ("Business as Usual" Case)	Varies by plant	Based on Appendix B to settlement agreement in Colorado PUC case 16A-0231E. <sup>32</sup>

### Replacement Resource Inputs & Assumptions:

Assumption/Input	Value	Source & Description
Solar PV Cost (2017/2019)	\$30.96/MWh	Based on Xcel Energy 2017 All-Source RFP Results. <sup>33</sup>
Wind Cost (2017)	\$19.30/MWh	Xcel Energy 2017 All-Source RFP Results. <sup>34</sup>

<sup>28</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>29</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>30</sup> See

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

<sup>31</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)

<sup>32</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)

<sup>33</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=881732&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=881732&p_session_id=)

<sup>34</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=881732&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=881732&p_session_id=)

Wind Cost (2019)	\$26.41/MWh	Assumes an average \$7.11/MWh increase over 2017 RFP value due to phaseout of the PTC. This is based on the assumption that the 2017 RFP reflects an 80% PTC and a new wind projects would be evenly split between a 60% PTC (2018 commence construction) and 40% PTC (2019 commence construction).
Market Energy Prices	Varies by month	Based on OTC Global Holdings Forward Power Index for Four Corners as of 4/22/2019. Prices are based on published values through 2027 and escalated at 2% annually for subsequent years.
Capacity Price (2019)	\$36.06/kW-yr	Represents midpoint of \$11.16/kW-yr (\$2.79/kW-mo x 4mo), consistent with market capacity value estimated in Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G) <sup>35</sup> and \$60.96/kW-yr (\$5.08/kW-mo x 12 mo), consistent with new combustion turbine from Xcel Energy 2017 All-Source RFP Results. <sup>36</sup>
Replacement Date	12/31/2022	--
Capacity Value	Varies by resource	Consistent with Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G). <sup>37</sup> See Tables 2.7-4 and 2.7-5.

### Social Cost of Carbon Inputs and Assumptions:

Assumption/Input	Value	Source & Description
SCC Cost (2020)	\$46/short ton	Based on SB 19-236
Escalation rate, 2020-2030	2.1%/yr	Based on Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document. <sup>38</sup>
Escalation rate, 2030-2040	1.9%/yr	Based on Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document. <sup>39</sup>
Escalation rate, 2040-2050	1.6%/yr	Based on Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document. <sup>40</sup>
Discount Rate	3%	Used only for computing the net present value of the cost of carbon portion of the analysis.

### Securitization Inputs and Assumptions (Xcel Energy Only):

Assumption/Input	Value	Source & Description
Equity Ratio	56.0%	Consistent with Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G). <sup>41</sup>
Debt Ratio	44.0%	Consistent with Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G). <sup>42</sup>
Return on Equity	9.83%	Consistent with Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G). <sup>43</sup>
Cost of Debt	4.67%	Consistent with Xcel's 2016 Electric Resource Plan 120-Day Report, filed June 6, 2018 in CPUC Proceeding No. 16A-0396E (Appendix G). <sup>44</sup>
Effective Tax Rate	24.68%	Based on filings in Xcel Energy 2019 rate application (reflects updated tax rate from Tax Cuts and Jobs Act).

<sup>35</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

[https://www.dora.state.co.us/pls/efi/efi.p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=887132&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.p2_v2_demo.show_document?p_dms_document_id=887132&p_session_id=)

<sup>37</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>38</sup> [https://www.epa.gov/sites/production/files/2016-12/documents/sc\\_co2\\_tsd\\_august\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf)

<sup>39</sup> [https://www.epa.gov/sites/production/files/2016-12/documents/sc\\_co2\\_tsd\\_august\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf)

<sup>40</sup> [https://www.epa.gov/sites/production/files/2016-12/documents/sc\\_co2\\_tsd\\_august\\_2016.pdf](https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf)

<sup>41</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>42</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>43</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

<sup>44</sup> See [https://www.dora.state.co.us/pls/efi/efi.show\\_document?p\\_dms\\_document\\_id=887196&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=887196&p_session_id=)

Rate of Return (after tax WACC)	7.05%	Computed from capital cost structure above
Securitization Bond Interest Rate	3.50%	Assumed based on estimated interest rate for a AAA-rated bond.
Securitization Bond Tenor	20 years	Assumed tenor for amortizing bond in securitization analysis.
Depreciable Plant	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E, p 243-246. <sup>45</sup>
Coal Unit Cost of Removal (net of salvage)	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E, p 255-258. <sup>46</sup>
Depreciation Reserve – Plant Life	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E, p 243-246. <sup>47</sup>
Depreciation Reserve – Cost of Removal	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E, p 243-246. <sup>48</sup>
Depreciation Expense – Plant Life	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E, p 228-231. <sup>49</sup>
Depreciation Expense – COR	Varies by plant	Based on Exhibit B to settlement agreement in Colorado PUC case 16A-0231E, p 228-231. <sup>50</sup>

<sup>45</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)

<sup>46</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)

<sup>47</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)

<sup>48</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)

<sup>49</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)

<sup>50</sup> [https://www.dora.state.co.us/pls/efi/efi\\_p2\\_v2\\_demo.show\\_document?p\\_dms\\_document\\_id=852810&p\\_session\\_id=](https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=852810&p_session_id=)