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FUTURE OF ELECTRICITY COSTS IN COLORADO

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ABOUT COMMON SENSE INSTITUTE

Common Sense Institute is a non-partisan research organization dedicated to the protection and promotion of Colorado's economy. CSI is at the forefront of important discussions concerning the future of free enterprise and aims to have an impact on the issues that matter most to Coloradans. CSI's mission is to examine the fiscal impacts of policies, initiatives, and proposed laws so that Coloradans are educated and informed on issues impacting their lives. CSI employs rigorous research techniques and dynamic modeling to evaluate the potential impact of these measures on the economy and individual opportunity.

TEAMS & FELLOWS STATEMENT

CSI is committed to independent, in-depth research that examines the impacts of policies, initiatives, and proposed laws so that Americans are educated and informed on issues impacting their lives. CSI's commitment to institutional independence is rooted in the individual independence of our researchers, economists, and fellows. At the core of CSI's mission is a belief in the power of the free enterprise system. Our work explores ideas that protect and promote jobs and the economy, and the CSI team and fellows take part in this pursuit with academic freedom. Our team's work is informed by data-driven research and evidence. The views and opinions of fellows do not reflect the institutional views of CSI. CSI operates independently of any political party and does not take positions.

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INTRODUCTION

Colorado's electricity sector is on the brink of rapid transformation. Driven by policy and propelled by new technologies and innovations, a large expansion to electricity generation is set to significantly reshape how much electricity Coloradans use, where their power comes from and, ultimately, how much they pay.

A recent report from the Colorado Energy Office (CEO), titled *Pathways to Deep Decarbonization in Colorado's Electric Sector by 2040* (referred to as the *Pathways Report*), estimates that achieving the state's emission reduction goals will cost $108 billion through 2050.[i] This figure reflects the investment required to more than triple Colorado's electric generation and storage capacity—from 21,816 megawatts to 67,256 megawatts. Meeting these capacity goals will require adding 55,068 megawatts of new generation capacity (45% in storage and 41% in wind and solar) and retiring 8,669 megawatts of existing capacity (49% in natural gas and 48% in coal). The *Pathways Report* also explores six alternative scenarios aimed at achieving 100% carbon emission reduction. These scenarios carry additional costs, ranging from 20% to 42% above the baseline estimates, varying based upon the type of electricity resources being prioritized. Importantly, the report's cost estimates do not include those of additional investments needed to expand transmission and distribution infrastructure.

Colorado's long-term economic competitiveness will depend heavily on the cost and reliability of its power supply. Ultimately, electricity consumers, both households and businesses, will bear the costs of future power sector investments.

This raises a critical question for policymakers and consumers alike: How will future changes to the electric power sector impact electricity prices?

Using publicly available reports and models, this analysis seeks to answer that question. It uses the key findings of the *Pathways Report* and integrates them with modeling tools developed by the electric regulatory agency, the Public Utilities Commission, to quantify the impact of future electric sector investments on electricity rates. While the results do not reflect the specific plans or modeling of any individual utility, they leverage the latest tools shared by the State of Colorado to inform policy discussions. This report does not address the feasibility of emerging technologies nor the reasonableness of assumptions underlying the results in the *Pathways Report.*

Given the high cost of living in Colorado and the bipartisan interest in making Colorado more affordable, it is critical that energy policy discussions account for anticipated costs to consumers and compares those costs to anticipated benefits, such as emission reductions. Colorado leaders, businesses and residents share an interest in ensuring that cumulative impacts of policy decisions do not drive electricity prices to levels that strain households and businesses nor undermine Colorado's economic competitiveness.

Key Findings

- **Driven by state policy mandates to reduce greenhouse gas emissions, electricity prices are projected to grow at more than three times the rate of inflation and nearly 13 times the growth rate from 2010 to 2020.**
  - By 2030 -
    - The average household will be spending $390 to $504 more annually due to rates outpacing inflation and historic trends.
    - All households combined will spend between $970 million and $1.25 billion more.
    - The average electricity rate will grow by 56%, from 12 cents/kWh to 18.4 cents/kWh. Rates would grow just 16% at a 2.5% rate of inflation and only 4% at the growth rate seen between 2010 and 2020.
- Between now and 2040, electricity rates that outpace inflation and historical trends will have large costs for consumers.
  - Cost of $16 billion to $23 billion or between $6,400 and $9,280 more per household.
  - Cost of $16.3 billion to $23.5 billion or between $41,700 and $60,200 more per commercial business consumer.
  - Cost of $11.6 billion to $16.8 billion or between $770,000 and $1.1 million more per industrial consumer.
  - Though electricity prices have no reason to grow at the full rate of inflation, this comparison point is used because the *Pathways Report* does not offer a scenario driven solely by the most cost-effective technology.
  - Electric rate estimates are conservative as they do not include the costs of large new transmission and distribution needed to support the capacity buildout.
- **Higher electricity prices cause economic ripple effects.** Though new spending on electric generation capacity will have isolated and temporary regional benefits, elevated electricity prices will have broad inflationary impacts on Colorado's economy as demonstrated by dynamic economic impact modeling.
  - Economic impact in 2030 -
    - GDP slowdown of $2.6 billion
    - 25,000 fewer jobs
    - $1,380 decrease in real disposable income for a family of four

- **Electricity prices surge because of large investments in new wind and solar, not because of natural gas prices.** The *Pathways Report* indicates that electric power generation capacity per capita will double by 2040, growing from 3.4 kilowatts per Coloradan to 6.9 kilowatts. Larger levels of capacity are needed to meet current laws to **1)** replace early retirements of coal and natural gas power generation, **2)** add additional generation to account for lower capacity factors of renewables and **3)** increase storage to accommodate the intermittency of renewables.
- **There remain important technical questions about the full cost and feasibility of the projected power sources needed to comply with state policy.** The *Pathways Report* estimates that wind and solar will provide over 70% of Colorado's electricity. However, that level of renewables relies on the assumption that remaining gas power plants will only need to run "a few hours each year." It is unclear what the costs, operational challenges, and related emissions of such limited use might be.

MODELING CONSUMER ELECTRICITY PRICES

Electric rate payers and consumers ultimately bear the cost of electricity investments. Most electricity markets, including Colorado's, are regulated by a state Public Utilities Commission (PUC). Each electric utility must submit plans for how they will meet electricity demand and reliability standards while complying with state law. Once these plans are approved, the PUC authorizes electricity rate increases necessary for the utility company to cover costs and provide returns to investors.

Although each utility submits its own plans and has a unique portfolio of investments impacting its rates, a recent state report sheds light on the trajectory of investments and prices in aggregate. The Colorado Energy Office's 2024 report, titled *Pathways to Deep Decarbonization in Colorado's Electric Sector by 2040: An Analysis of Colorado's Energy System in Meeting the State's Clean Energy Goals* (referred to as the *Pathways Report*), estimates the annual aggregate costs associated with investments in new electric generation capacity as well as the operation and maintenance costs of the overall system. The modeling of future costs was conducted in partnership with Ascend Analytics, using their proprietary model of the state's electricity system.

While the *Pathways Report* provides a comprehensive evaluation of the electric generation resources needed to meet state policy goals and their costs, it does not estimate how the aggregate investments and operational expenses will translate into electricity prices.

Separately, the PUC commissioned an electricity rate forecasting model, termed the 30-Year Rate Model, which is publicly available for download on their website. This model was developed in partnership with Concentric Energy Advisors.[ii] The investment and operational cost projections from the *Pathways Report* were integrated into the 30-Year Rate Model by CSI to estimate the impact on electricity prices over the next 15 years.

Accurate and comprehensive electricity price and cost estimates are critical for transparency with ratepayers and voters.

Integrated Modeling Framework - Electricity Price Projections

Results from Pathways Report

- Capital expenditure
  - New electricity generation
  - Operation and maintenance of electricity generation
- Sales Forecast

→

Inputs to "30 Year Rate Model"

- Swapped default capex and O&M values for results from *Pathways Report*
- Zeroed out default fuel costs
- All other costs and assumptions built into the rate forecasting model remained the same

→

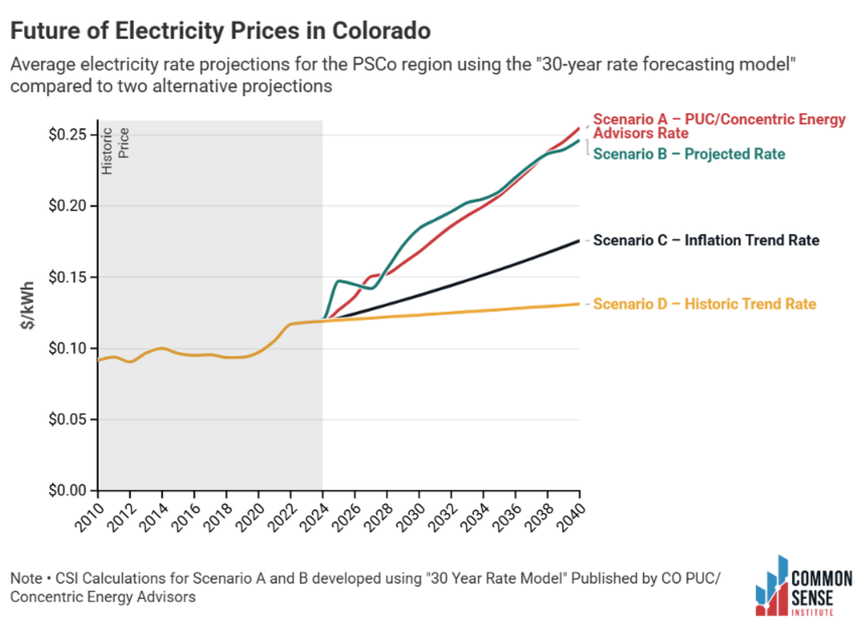
Average Electricity Prices through 2040

CSI Integrated Modeling Results

Figure 1 compares electricity price projections from the integrated modeling (where results from the *Pathways Report* were input into the 30-Year Rate Model) to three alternative trends.

- **Scenario A** – PUC/Concentric Energy Advisors Rate - The baseline rate projection as originally built into the PUC/Concentric Energy Advisors 30-Year Rate Model before incorporating costs from the *Pathways Report*.
- **Scenario B** – Projected Rate - This scenario uses the *Pathways Report* capital expenditures, operation and maintenance (O&M) costs, and sales volume integrated into the 30-Year Rate Model.
- **Scenario C** – Inflation Trend Rate – This projection assumes average electricity prices grow at a steady inflation rate of 2.5% annually.
- **Scenario D** – Historic Trend Rate - This projection assumes average electricity prices grow annually at the same rate as they did between 2010 and 2020 (0.605%).

FIGURE 1



The electricity price projections from the integrated modeling effort are very similar to the price projections that were already included in the 30-Year Rate Model prior to the adjustments. In other words, both projections suggest that electricity prices will need to grow at a much faster rate than both recent history and inflation, in-order to pay for the large levels of new investments in electric power generation and the decommissioning of existing coal and natural gas power generation.

There are a few important factors that should be considered regarding interpreting these results.

- The price estimates are derived from publicly available resources and reports. While these resources and reports are being used as the basis for policy discussions, they do not reflect the exact costs nor prices faced by any individual utility.
- The prices account for a baseline level of transmission and distribution investment required to both maintain the system and meet plans prior to 2024. **They do not account for large new investments in transmission and distribution that will be needed to meet the expected buildout of electricity generation modeled in the** *Pathways Report.* Rate increases needed to expand the transmission and distribution infrastructure would be in addition to rates estimated in Scenario B -Projected Rate.

FIGURE 2

Electricity Rate Under Alternative Scenarios ($kWh)					
	2023	2025	2030	2035	2040
Scenario A - PUC/Concentric Energy Advisors Rate	$0.118	$0.127	$0.168	$0.207	$0.255
Scenario B - Projected Rate	$0.118	$0.147	$0.184	$0.210	$0.246
Scenario C - Inflation Trend Rate	$0.118	$0.121	$0.137	$0.155	$0.176
Scenario D - Historic Trend Rate	$0.118	$0.120	$0.123	$0.127	$0.131

Figure 3 shows the difference between the policy baseline scenario in the *Pathways Report* relative to both inflation of 2.5 percent and the continuation of the 2010-2020 average growth rate in electricity prices. **Relative to inflation, the prices under the baseline scenario in the Pathway's Report would be 21% higher this year, 34% higher by 2030 and 46% higher by 2040.**

FIGURE 3

Difference Between Pathway's Report and Alternatives ($/kWh)						
	2025		2030		2040	
	$/kWh	% Difference	$/kWh	% Difference	$/kWh	% Difference
Difference between Projected Rate and Inflation Trend of 2.5%	$0.026	21%	$0.047	34%	$0.071	46%
Difference between Projected Rate and Historic Trend Rate	$0.027	23%	$0.061	49%	$0.115	88%

Pathways Report Alternative Scenarios to Achieve 100% Emission Reduction

The *Pathways Report* includes 6 additional scenarios aimed at achieving zero carbon emissions from the electricity sector by 2040 through select technologies. The report baseline, labeled the Economic Deployment Scenario, achieves a 94% reduction in carbon emissions.

The 6 scenarios are described in the report in the following manner. Importantly, technologies such as net zero gas, or carbon capture and storage, were not chosen to be included in any of the alternatives.

Optimized 100 (OT100) – "A cost-optimized scenario required to meet zero carbon emission by 2040 target, that could choose from all technology options. It is the most efficient pathway to a carbon free grid in 2040."

Wind, Solar, and Battery only (WSB) – "The model was only allowed to select wind, solar, and batteries to meet the zero-carbon emissions requirement."

Accelerated Geothermal Adoption (GEO) – "The scenario is required to use geothermal to meet at least a certain percentage of electric capacity needed by particular years – 2% in 2034, 4% in 2036, 8% in 2038, and 10% in 2040. The model selected other resources to meet a 2040 zero emissions target on a cost optimized basis."

Distribution-System Level Focus/Demand Side Focus (DSF) – "This scenario focused on meeting state electricity needs with customer-sited, distribution level resources. Because of that, the scenario assumes higher amounts of grid interconnected distributed energy resources (DERs), vehicle-to-grid participation by EV owners, demand response, beneficial electrification, and energy efficiency to model the impacts on the grid and bulk system resources than the other scenarios."

Small modular reactors (SMR) – "This scenario builds out small modular nuclear reactors in the late 2030s: two 320 MW reactors are built each year from 2035 to 2040, spread across the state. The model is allowed to select other resources to meet a 2040 zero emissions target on an economic basis."

Hydrogen Limited (H2lim) – "This is a sensitivity of the Optimized 100 scenario. This scenario limits the model's use of hydrogen to evaluate which resources could potentially replace hydrogen if hydrogen was unavailable at the levels shown in the Optimized 100 scenario."

Each of the 6 scenarios range in costs above the baseline from 20% to 41%, or an additional $8.6 billion to $17.8 billion in net present value. It is very likely that these alternative scenarios would translate to electricity prices even greater than estimated for the baseline. However, due to some discrepancies in the report data, and lack of data related to growth in electricity consumption on a per consumer basis across scenarios, estimates for what electricity prices would look like under the 6 alternative scenarios were not developed.

FIGURE 4

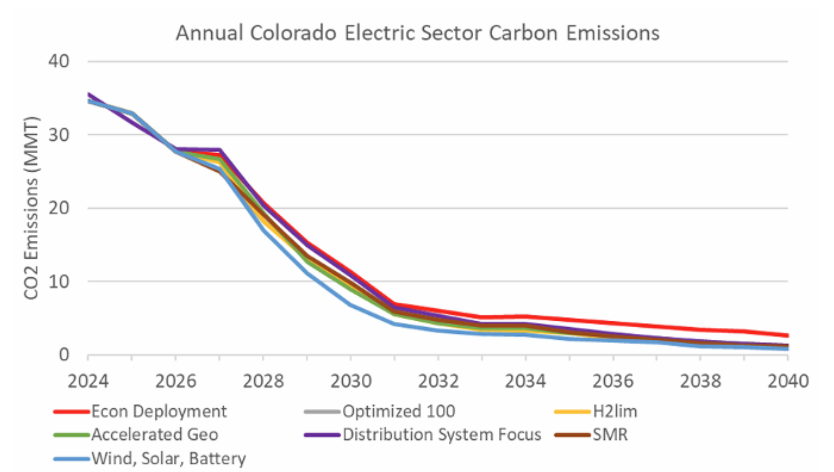
Total Costs of Electricity Sector Scenarios in Pathways Report

2023-2040 NPV ($B)	Econ Deploy	OT100	H2lim	Geo	DSF	WSB	SMR
Net import costs	$3.6	$1.9	$1.7	$1.7	$2.6	$0.2	$1.7
Capital costs	$24.9	$33.7	$36.0	$36.8	$37.5	$42.4	$42.4
O&M costs	$14.6	$16.0	$16.4	$16.2	$16.0	$18.4	$16.7
Total costs	$43.1	$51.6	$54.1	$54.7	$56.1	$61.0	$60.8
Total Cost % Difference to Econ Deployment (policy baseline) Scenario	0%	20%	26%	27%	30%	42%	41%

Source: Pathways Report

While the net present value cost of each alternative scenario would range from 21% to 42% above the policy baseline, the cumulative emission reductions would only range from 4% to 15% lower. Figure 5 shows the annual CO2 emission projections from just the electric power sector by scenario in the *Pathways Report*.

FIGURE 5



Source: Pathways Report

While the net present value cost of each alternative scenario would range from 21% to 42% above the policy baseline, the cumulative emission reductions would only range from 4% to 15% lower. Figure 5 shows the annual CO2 emission projections from just the electric power sector by scenario in the *Pathways Report*.

Between 2023 and 2040 the difference in cumulative GhG emissions across each of the 6 scenarios compared to the policy baseline range from a reduction of 10.2 million metric tonnes(DSF scenario) to a reduction of 37.9 million metric tonnes (WSB scenario). Given the difference in the net present value cost of each scenario, the estimated cost per metric ton of CO2 reduced ranges from $373 to $1,748.

FIGURE 6

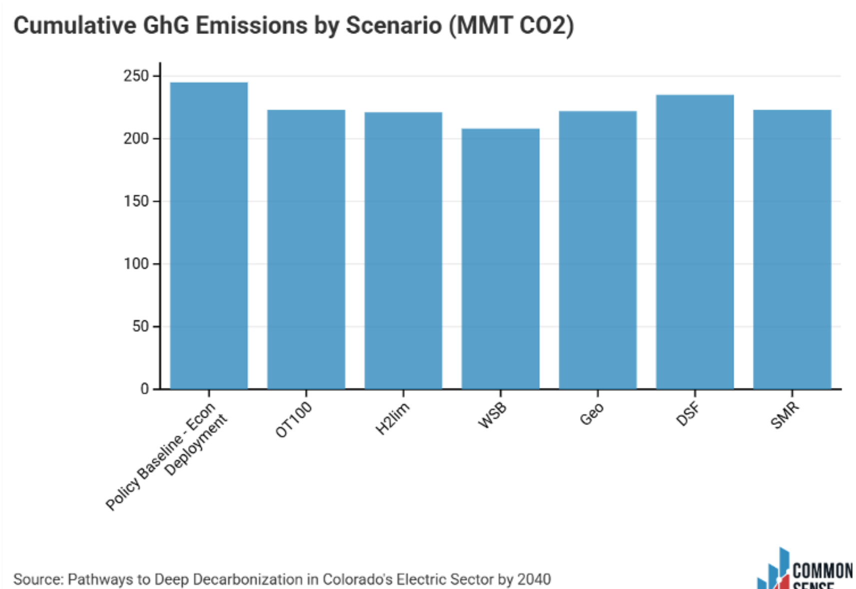


FIGURE 7

Difference in CO2 Emissions by Scenario Compared to Economic Deployment Scenario			
	Difference in Cumulative CO2 (MT)	Difference in NPV Capital + OM Cost	Cost Per Additional Reduction in MT CO2
OT100	-22,956,812	$8,564,253,661	$373
H2lim	-24,832,143	$11,043,483,538	$445
WSB	-37,951,558	$11,609,291,964	$306
Geo	-23,051,466	$13,047,791,260	$566
DSF	-10,245,110	$17,910,092,270	$1,748
SMR	-22,331,884	$17,768,729,859	$796

Rate Impacts to Electricity Customers

While each electricity consumer can control their utility bill to a degree, higher electricity rates directly contribute to higher utility bills for households, commercial businesses and industrial businesses.

HOUSEHOLDS

In 2023, the average Colorado household consumed 8,302 kWh of electricity at the average rate of 14 cents per kWh, resulting in an annual electricity expenditure of $1,178. Between 2010 and 2020, average electricity prices were relatively flat and less than 10 cents per kWh; a typical household's electricity cost averaged about $806 per year over this period. In other words, **by 2023 household electricity costs increased by $372, or 46%, from the average over the prior decade.**

By 2030 electricity rates are projected to be 4.7 cents per kWh higher than a 2.5 percent annual inflation trend, and 6 cents higher than if rates had continued to grow at the average annual rate of the previous decade (0.6% annual increase). By 2035, rates are projected to be 5.5 cents per kWh above the trend growing at the assumed inflation rate and 8.3 cents per kWh above the historic growth trend rate.

This means that if household electricity consumption remains steady, the average Colorado household will pay an additional $390 to $457 annually, or $32 to $38 more per month through 2035 as a result of just the growth in new electric power generation envisioned in the baseline scenario of the *Pathways Report*. If household consumption rises by 20%, reflecting policy-driven goals for increased electrification, annual costs would increase to $467 to $549 over the same period.

For residential households, the cost of electricity exceeding a 2.5 percent inflation rate would total $16 billion by 2040. Each household would spend an additional $6,423 between

FIGURE 8

Projected Higher Costs to Households of Electricity Prices Outpacing Inflation		
	Annual Cost at 2023 Consumption Level	Annual Cost at 120% of 2023 Consumption Level
2023	$0	$0
2024	$13	$16
2025	$215	$258
2026	$170	$204
2027	$121	$145
2028	$210	$252
2029	$320	$384
2030	$389	$467
2031	$412	$494
2032	$430	$516
2033	$453	$544
2034	$445	$534
2035	$457	$549
2036	$506	$607
2037	$549	$659
2038	$577	$693
2039	$567	$680
2040	$587	$705
18-year Total	$6,423	$7,708

* The slight decrease in annual costs shown in 2027 is primarily due to an increase in the value of production tax credits, spurred by the passage of the Inflation Reduction Act.

2023 and 2040. Notably, these cost estimates are conservative, as they compare projected rates to a high inflation trend (The Federal Reserve has an overall inflation target of 2 percent). If the Projected Rates were compared to rate at the historic trend, the total cumulative cost to households grows to $9,282 by 2040. These costs do not account for any growth in the amount of electricity consumed per household.

The volatility in prices in the first few years is primarily due to an increase in federal production tax credits authorized as part of the Inflation Reduction Act. There is some volatility in the annual investment assumptions that also causes rates to decrease in 2026 and 2027, but that effect is smaller than that of the production tax credits.

COMMERCIAL BUSINESSES

In 2023 the average Colorado commercial business consumed 53,880 kWh of electricity at an average price of 11.6 cents/kWh, spending a total of $6,242 on electricity last year.

By 2030, these rates are projected to be 4.7 cents/kWh higher than the inflation trend. By 2035 they are projected to be 5.5 cents/kWh higher. If commercial consumption levels stay the same, the average Colorado commercial business will be spending over $2,500 more annually by 2030 compared to the scenario where rates grow at 2.5%. Compared to rates growing at the historic trend, commercial businesses will be spending $3,300 more in 2030. If commercial consumption increases by just 20 percent due to increased electrification, the annual cost increase from higher rates would be $3,500 higher by 2035 compared to a rate trended at inflation.

The total cost to the commercial sector for costs rising above inflation would be $16.2 billion as each business spends an additional $41,686 to $50,023 by 2040. This only includes the cost of electricity and not additional costs associated with swapping out existing equipment for electric powered equipment.

FIGURE 9

Projected Higher Costs to Commercial Businesses of Electricity Prices Outpacing Inflation

	Annual Cost at 2023 Consumption Level	Annual Cost at 120% of 2023 Consumption Level
2023	$0	$0
2024	$87	$104
2025	$1,398	$1,677
2026	$1,105	$1,325
2027	$784	$941
2028	$1,364	$1,637
2029	$2,075	$2,490
2030	$2,528	$3,033
2031	$2,672	$3,206
2032	$2,792	$3,350
2033	$2,943	$3,532
2034	$2,886	$3,463
2035	$2,967	$3,560
2036	$3,284	$3,941
2037	$3,563	$4,276
2038	$3,747	$4,497
2039	$3,680	$4,416
2040	$3,812	$4,575
18-year total	$41,686	$50,023

* The slight decrease in annual costs shown in 2027 is primarily due to an increase in the value of production tax credits, spurred by the passage of the Inflation Reduction Act.

INDUSTRIAL BUSINESSES

In 2023 the average Colorado industrial business consumed 996,042 kWh of electricity at a price of 8.6 cents/kWh, spending a total of $85,967 on electricity last year.

By 2030, the rates are projected to be 4.7 cents/kWh higher than the inflation trend. By 2035 they are projected to be 5.5 cents/kWh higher. This means that if industrial consumption levels stay the same, the average Colorado industrial business will be spending $54,843 more annually in a decade. If industrial consumption increases by just 20%, given other policy objectives to increase electrification, then the annual cost would be between $56,072 and $65,812 more annually.

The total cost to the commercial sector of prices rising above inflation would be $11.6 billion to $13.9 billion as each business spends an additional $770,629 to $924,755.

FIGURE 10

Projected Higher Costs to Industrial Businesses of Electricity Prices Outpacing Inflation

	Annual Cost at 2023 Consumption Level	Annual Cost at 120% of 2023 Consumption Level
2023	$0	$0
2024	$1,604	$1,925
2025	$25,839	$31,007
2026	$20,418	$24,502
2027	$14,494	$17,393
2028	$25,217	$30,261
2029	$38,356	$46,027
2030	$46,727	$56,072
2031	$49,388	$59,265
2032	$51,614	$61,937
2033	$54,405	$65,286
2034	$53,355	$64,026
2035	$54,843	$65,812
2036	$60,716	$72,860
2037	$65,873	$79,047
2038	$69,277	$83,133
2039	$68,025	$81,630
2040	$70,476	$84,572
18-year total	$770,629	$924,755

* The slight decrease in annual costs shown in 2027 is primarily due to an increase in the value of production tax credits, spurred by the passage of the Inflation Reduction Act.

Production Tax Credits Keep Rates Lower yet Still Have a Cost

Production tax credits (PTCs) are federal tax incentives designed to encourage renewable energy production by providing a per-kilowatt-hour credit based on the value of renewable electricity sales. These credits act as supplemental revenue for utilities operating renewable assets. PTC's do not change the total cost of delivering energy, rather they shift who pays for the electricity from ratepayers to taxpayers. Based on the 30-Year Rate Model, between 2024 and 2053, the value of PTCs across Colorado is projected to total $21.9 billion. While these federal tax credits help to keep electricity prices lower, taxpayers still bear additional costs. And while electricity consumers can adjust their demand as prices increase, taxpayers do not have a similar avenue to reduce their tax burden.

Coloradans indirectly support PTCs through federal taxes. Without these tax credits, ratepayers would bear the full cost of electric power sector investments and operational expenses through higher rates. Just to illustrate the scale of the PTCS, in 2023 Colorado businesses paid $4.7 billion in federal income taxes. The projected PTC value of $826 million in 2035 represents 17 percent of this total. Taxes will certainly grow by 2035 and therefore the actual percentage share will be smaller, but this comparison helps to understand the relative size of these credits.

For existing renewable energy production, PTCs are estimated to total $1.1 billion through 2030. For new renewable capacity added from 2024 through 2030, PTCs are estimated to total $1.4 billion. PTCs are projected to grow significantly beyond 2030, totaling $7 billion between 2031 and 2040.

By 2030, the annual value of PTCs will have grown by 2.8 times their current level, and by 2035 they are expected to be 4.6 times larger.

From 2020 to 2040, PTCs will represent over 2 cent per/kWh of taxpayer funded subsidies that otherwise would have been paid for by ratepayers. For Colorado households this equates to a cost of approximately $2,395 between 2024 and 2040. Without PTC's the total cost to households would increase nearly 40 percent, highlighting the significant financial impact of production tax credits on Colorado households and businesses for energy costs.

FIGURE 11

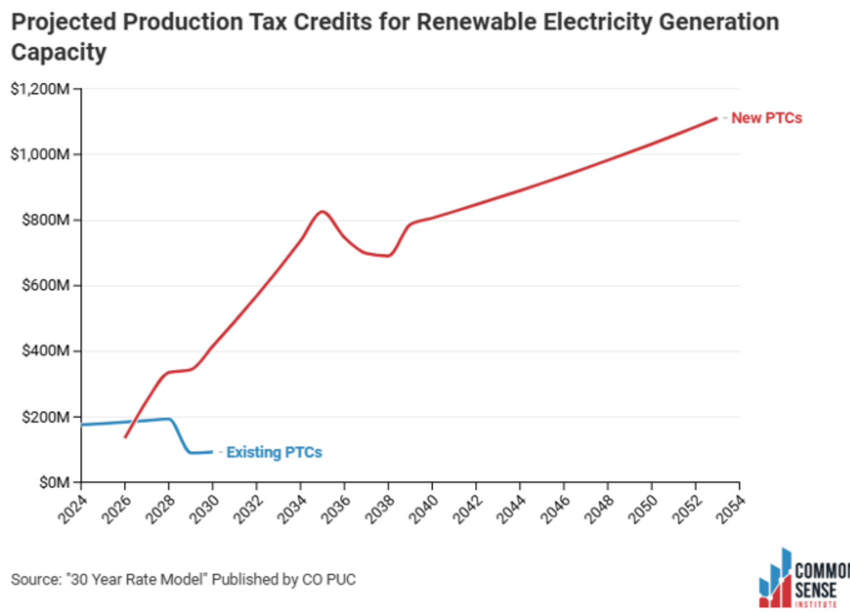
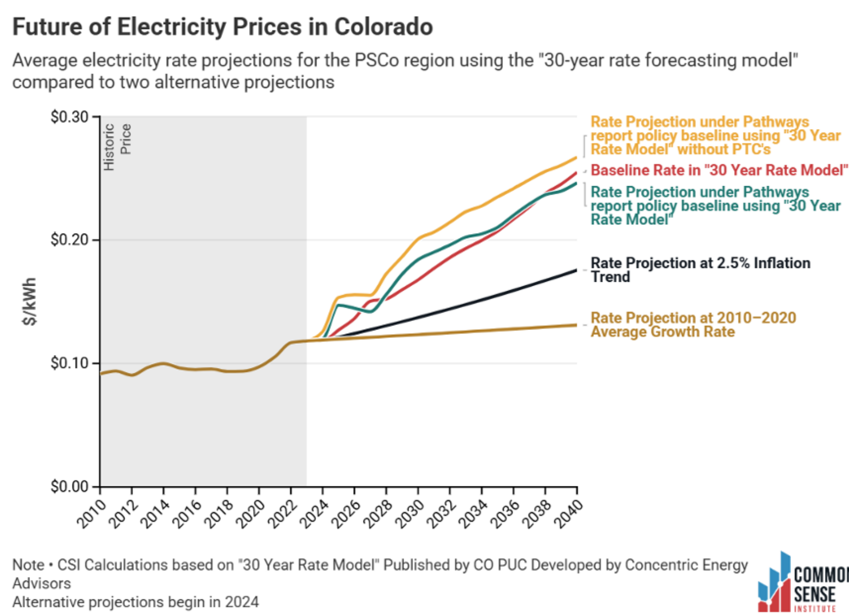


FIGURE 12



Economic Impacts of Higher Electricity Rates

Rising electricity prices act as a hidden tax on households and businesses, driving inflation and straining budgets. For families, the impact is immediate, higher energy bills leave less room for other essentials. For businesses, increased electricity costs are often passed down the line to consumers, compounding the burden on household budgets. Recent research on the increasing prices of electricity in Germany estimates that just a 1% increase in electricity prices, increases household inflation expectations by 1.4 basis points.[iii] This ripple effect touches every corner of the economy, reducing disposable income and limiting spending on other goods and services. The result is a cycle that dampens economic activity and constrains consumer choices, underscoring the far-reaching consequences of energy price increases. Rising electricity prices are generally regressive, as the cost burden is relatively higher for middle and lower-income households. In a time when policy is pursuing even greater levels of electricity use to replace other fuel sources, the stakes are even higher.

The impact to the Colorado economy can be estimated using the economic model PI+ developed by REMI. PI+ is a dynamic economic forecasting and simulation model with hundreds of policy variable levers that users can change to estimate the economic impact of policy changes across employment, income, GDP and many other factors.

While there are many factors that impact the overall trajectory of the economy, analyzing the impacts resulting from just the increase in electricity prices provides helpful perspective on the potential drag on the economy.

In 2024, the cost of electricity prices outpacing inflation totaled $91 million across households, and commercial and industrial businesses. By 2040 the grows to $4 billion.

FIGURE 13

Projected Direct Costs to Consumer Sectors of Electricity Outpacing Inflation - REMI Inputs

	Households	Commercial	Industrial	Total Costs
2024	$33,170,136	$33,919,868	$24,189,624	$91,279,627
2025	$534,244,855	$546,320,187	$389,602,932	$1,470,167,974
2026	$422,167,337	$431,709,424	$307,869,380	$1,161,746,141
2027	$299,671,968	$306,445,339	$218,538,515	$824,655,821
2028	$521,389,962	$533,174,740	$380,228,384	$1,434,793,086
2029	$793,043,620	$810,968,482	$578,334,292	$2,182,346,395
2030	$966,108,419	$987,944,998	$704,543,374	$2,658,596,791
2031	$1,021,132,467	$1,044,212,734	$744,670,163	$2,810,015,365
2032	$1,067,156,786	$1,091,277,323	$778,233,818	$2,936,667,927
2033	$1,124,870,028	$1,150,295,036	$820,321,726	$3,095,486,790
2034	$1,103,158,068	$1,128,092,328	$804,488,081	$3,035,738,477
2035	$1,133,929,002	$1,159,558,766	$826,928,065	$3,120,415,834
2036	$1,255,357,233	$1,283,731,593	$915,480,710	$3,454,569,536
2037	$1,361,972,234	$1,392,756,372	$993,230,672	$3,747,959,279
2038	$1,432,362,377	$1,464,737,516	$1,044,563,325	$3,941,663,218
2039	$1,406,464,342	$1,438,254,118	$1,025,676,947	$3,870,395,406
2040	$1,457,156,251	$1,490,091,796	$1,062,644,484	$4,009,892,530

The PCE-price index (personal consumer expenditures) calculated in the PI+ model increases approximately 0.3% in the initial years, growing to a 0.42% increase by 2035. These broad price increases, combined with the direct increase in the cost of production for firms, produces a negative impact to the Colorado economy of 1,000 jobs lost in the first year, growing to 25,000 jobs lost or not created by 2030. GDP is reduced by $51 million in the first year and grows to a reduction of over $3 billion by 2031. Direct costs to consumers are shown in the appendix.

The combination of job losses and higher prices means that real disposable income per capita will be lower by $296 in 2025 and over $346 by 2030. For a family of 4 that amounts to a loss between $1,184 and $1,384.

FIGURE 14

REMI Results - Dynamic Economic Impacts of Increased Electricity Prices			
	2025	2030	2040
Employment	-13,880	-25,500	-21,000
GDP (millions)	-$800	-$2,693	-$3,138
Real Disposable Income (billions)	-$2.30	-$4.70	-$7.00
Real Disposable Income per Capita	-$296	-$346	-$271

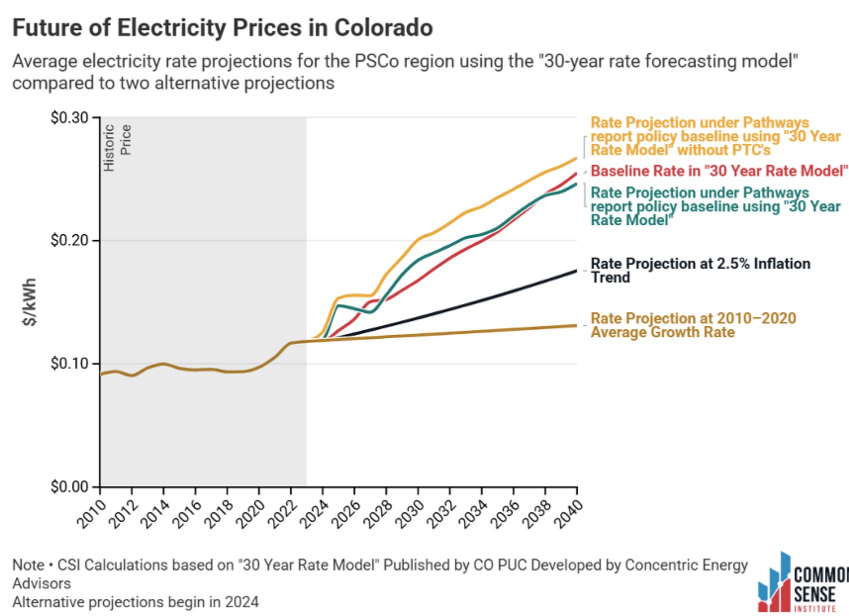
Natural Gas and Natural Gas Rate Impacts

An additional cost, not addressed within the *Pathways Report*, is the price of natural gas. Residential, commercial and industrial consumers use natural gas directly to power furnaces, stoves, dryers, and additional appliances. Utility companies have rate charges for this direct use and these prices have seen significant increases despite actual natural gas prices decreasing. The price paid by consumers is significantly higher than natural gas prices. Utilities are also actively increasing the rates for natural gas, to pay for increased electrification.[iv]

These costs are expected to continue to increase. As household electrification increases, consumers will become more exposed to higher electricity prices and higher rates for natural gas.

The figure here shows Colorado natural gas prices and consumption. This consumption is inclusive of natural gas consumed by both power generation and gas service use in homes and businesses. There is a growing disconnect in recent years between the prices residents pay for natural gas and the

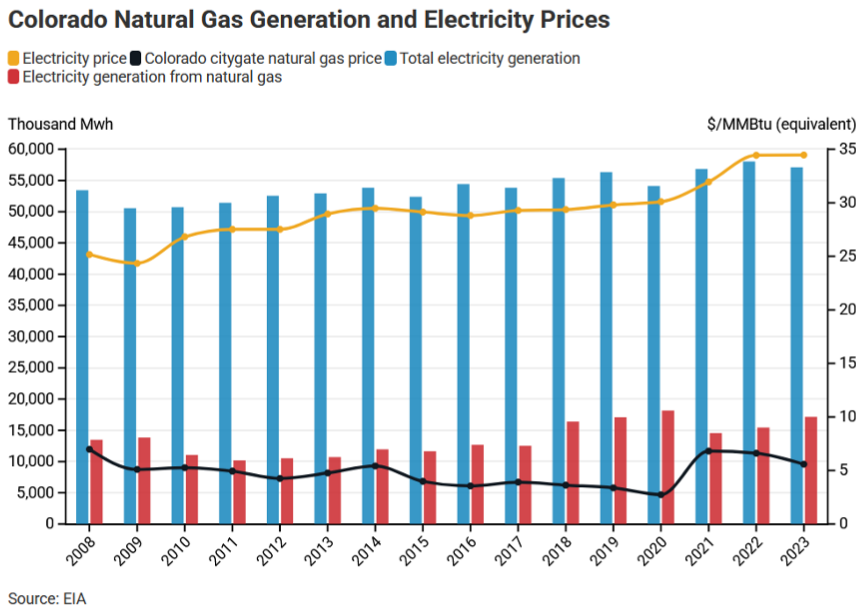
FIGURE 15



actual price of natural gas. The average price of natural gas paid by residents in the US in 2024 is $23 per MMBTU while the average price for Henry Hub natural gas has been about $2 per MMBTU. Unlike oil prices, where the consumer feels both inflation and deflation at the gas station pump with rising and falling oil prices, consumers are not seeing the significantly lower natural gas prices. Utility providers are not passing along cost savings for low natural gas prices to the consumer.

The following chart shows natural gas power generation vs. total power generation, natural gas prices, and electricity prices in the same $/MMBTU equivalent. This shows the growth in electricity prices despite the decline in actual natural gas prices.

FIGURE 16



SHIFT IN ELECTRICITY CAPACITY BY FUEL SOURCE

The rise in electricity prices is directly connected to the substantial investments in electric generation capacity. Capacity is the installed equipment used to produce electricity.

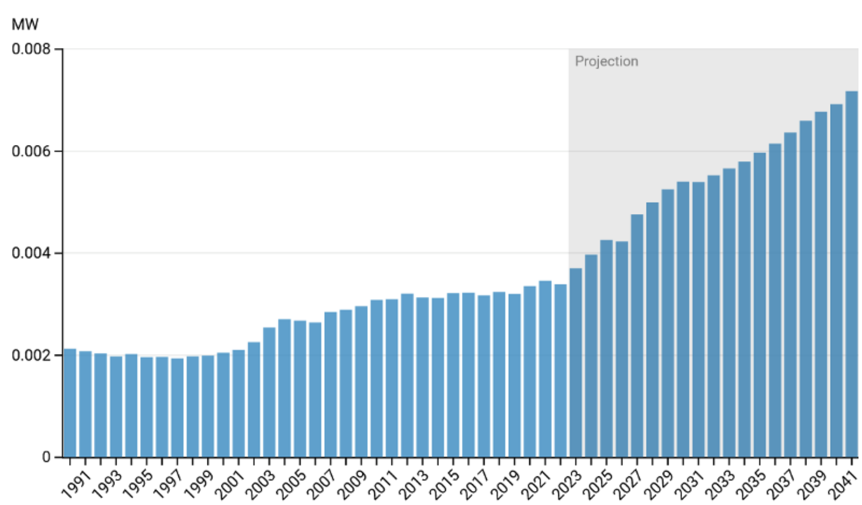
New generation capacity in the Pathway Report baseline is projected to increase rapidly on a per capita basis, due to a combination of three main factors:

- An increase in demand. The *Pathways Report* baseline includes a forecast for electricity demand (termed load forecast in report and reported in tWh) that grows by 62% by 2040.
- Retirement of power generation capacity from coal and natural gas and the addition of new capacity in wind, solar, and batteries. The baseline anticipates the retirement of 8,669 megawatts (MW) of existing capacity while adding 55,068 MW of new capacity. This means that 16 percent of newly added nameplate capacity will replace retired capacity.
- The increase in new generation capacity is primarily wind and solar power. The intermittency of these sources means that additional redundant capacity and backup storage are required. Consequently, nameplate capacity has to grow at an annual rate of 8.7 percent, over 1.5 times the historical average. Wind power generation capacity will increase by 85 percent, and solar power generation capacity will increase by 1,271 percent in just 10 years. This is an increase in wind capacity from 5,443 MW in 2023 to 10,654 MW by 2040. Solar power generation capacity increases from 2,160 MW to 12,059 MW by 2040.

FIGURE 17

Installed Electric Sector Generation Capacity per Coloradan (Megawatts)

Total electric power capacity per Coloradan is projected to double by 2040.



Source: Pathways to Deep Decarbonization in Colorado's Electric Sector by 2040

Figure 19 shows the change in the amount and type of electric power sector nameplate generating capacity by scenario. The figure shows the net change, inclusive of additions minus retirements within each fuel category. While the *Pathways Report* includes capacity projections through 2050 for the Economic Deployment scenario, it only includes projections for the additional 6 scenarios through 2041.

FIGURE 18

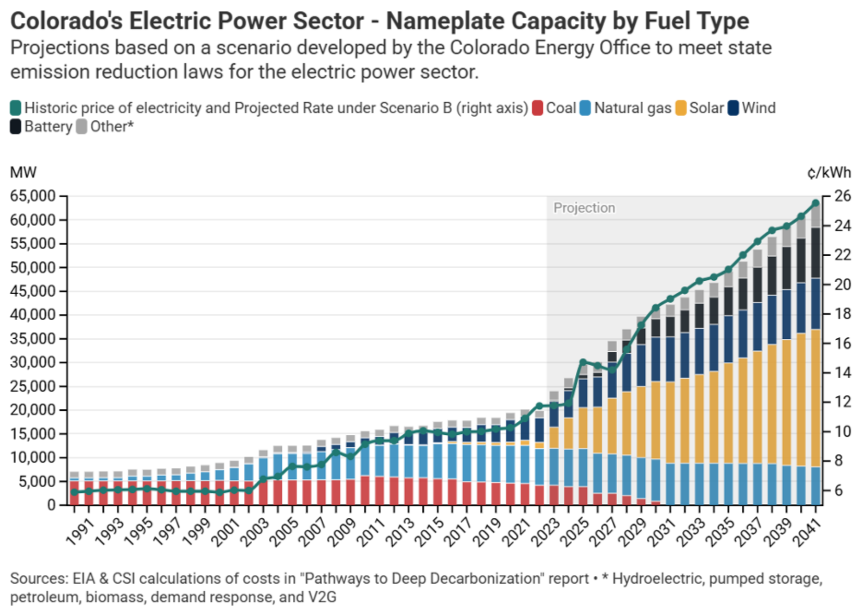
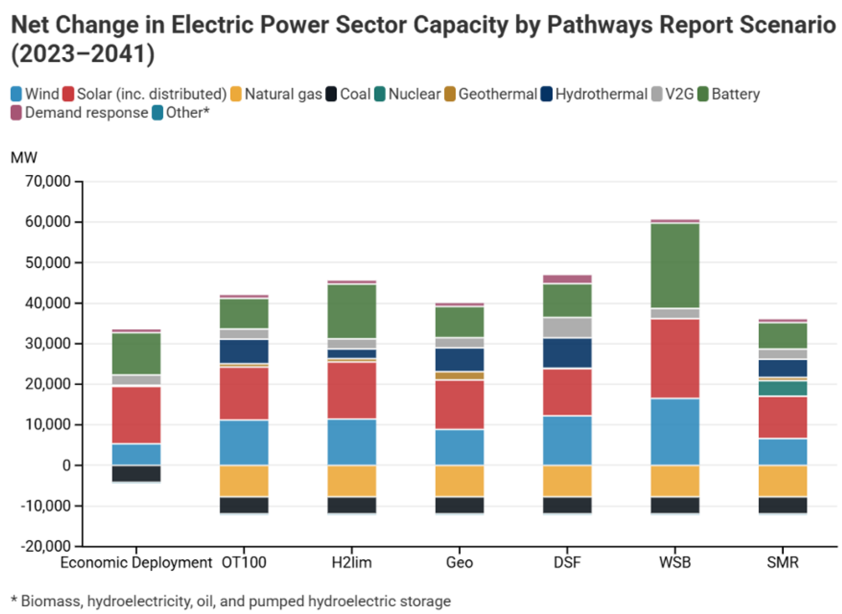


FIGURE 19



SHIFT IN ELECTRICITY GENERATION BY FUEL SOURCE

While electricity capacity accounts for the maximum volume of electricity a system can generate at single point in time, electric power generation captures the volume and source of electricity produced over time. This means that the share of capacity can be higher for some fuel sources than its share of actual power generation.

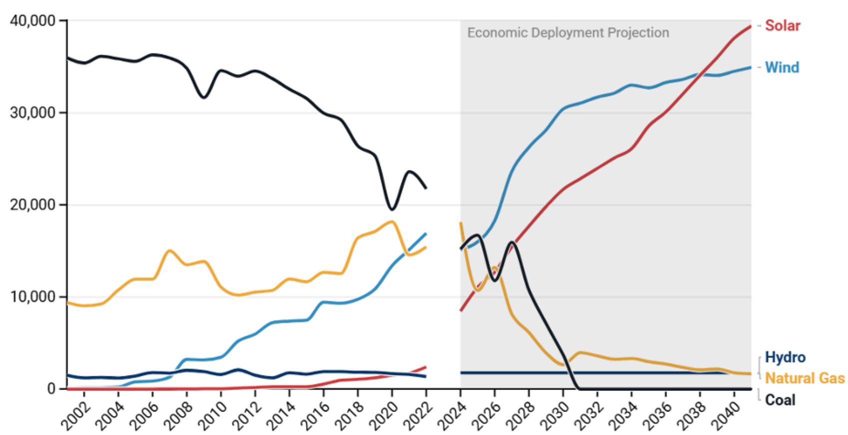
Each electricity fuel source has different capacity factors, or percentage of their total capacity that can be used for actual generation at any given time. This is driven by the technology itself - wind and solar produce power at lower capacity factors than coal, natural gas or nuclear. However, it is also driven by policy assumptions about what it would take to maintain greenhouse gas emissions below state mandated levels. For instance, electric power generated from coal, which remained the state's largest source of power generation in 2023, is planned to be completely phased out by 2031. Renewable fuel sources which presently generate about a third of Colorado's electricity (almost all of this is currently wind), will be responsible for nearly 100% of the power generation in 2041. Each scenario also includes an import threshold to satisfy reliability requirements.

Beyond just the cost of capital investment, the shift in generation towards wind and solar can also contribute to operational cost increases. The shift often corresponds with the reduction of a baseload power source, like coal in Colorado or nuclear in California. The removal of a consistent, and reliable baseload power source replaced by an intermittent power source requires both back up and redundancy. There are also greater transmission requirements, and operational costs associated with greater intermittency.

FIGURE 20

Total Electric Generation - Pathways Report Economic Deployment Scenario (Thousand MWh)

2023 is excluded due to discrepancies between the forecast and new historical data



Sources: EIA and Pathways Report • * Biomass and oil are excluded but are near zero. Storage such as V2G, battery, and pumped hydroelectric are considered part of generation in Pathways Report but are negative values and not included in this image.

The rapid growth in renewables coupled with the phasing out of a baseload source mimics the California grid over the past 15 years. California electricity prices rose given considerable increases in wind and solar additions, coupled with the reduction in baseload power generation from nuclear power starting around 2012. Nuclear power in California is akin to Colorado's coal, though coal is currently a far greater share within Colorado as it currently accounts for one-third of electricity generation.

Increasing penetration of wind and solar power into the grid also puts enormous economic and risk management pressure on dispatchable power sources—natural gas in particular. Weather conditions frequently change relative to forecasts, putting price pressure on natural gas operators who have to buy fuel on short notice in a competitive market. It is unreasonable to expect operators of natural gas fired generation assets to make forward purchases of fuel or enter into financial hedging arrangements to risk mange fuel costs when they really have no idea if their plants will be called upon to provide power. Unfortunately, when temperatures become extremely hot or extremely cold and power demand spikes, weather dependent power generation sources like wind and solar cannot meet this spiking power demand. Wind power often fails in the winter or summer because the wind does not blow in extreme heat or cold and solar power falters in extreme weather because solar panels cannot generate power when it is cloudy or when they are covered with snow. This leaves natural gas fired power generation to fill the gap in power demand. The operators of these natural gas assets must then scramble, at a time of weather crisis and likely prices spikes and potential fuel shortages, to procure fuel in

FIGURE 21

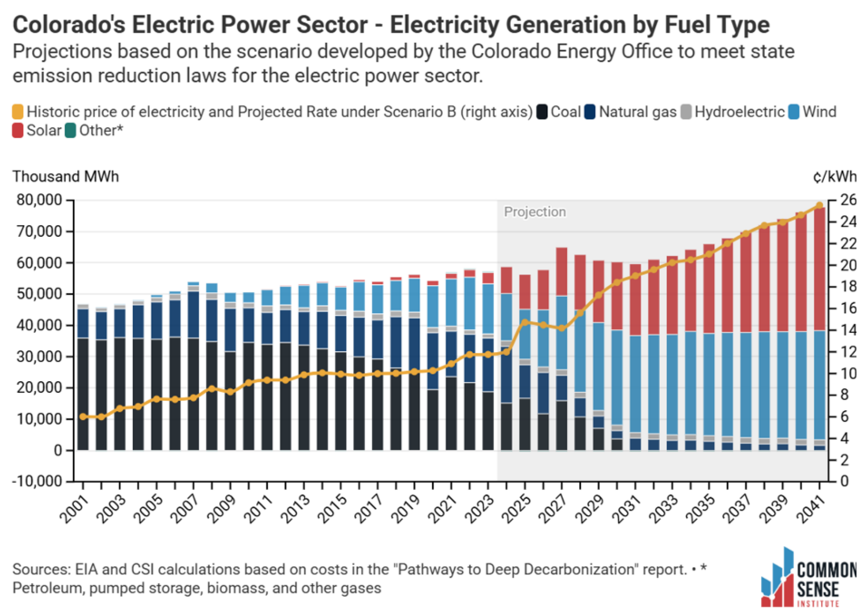
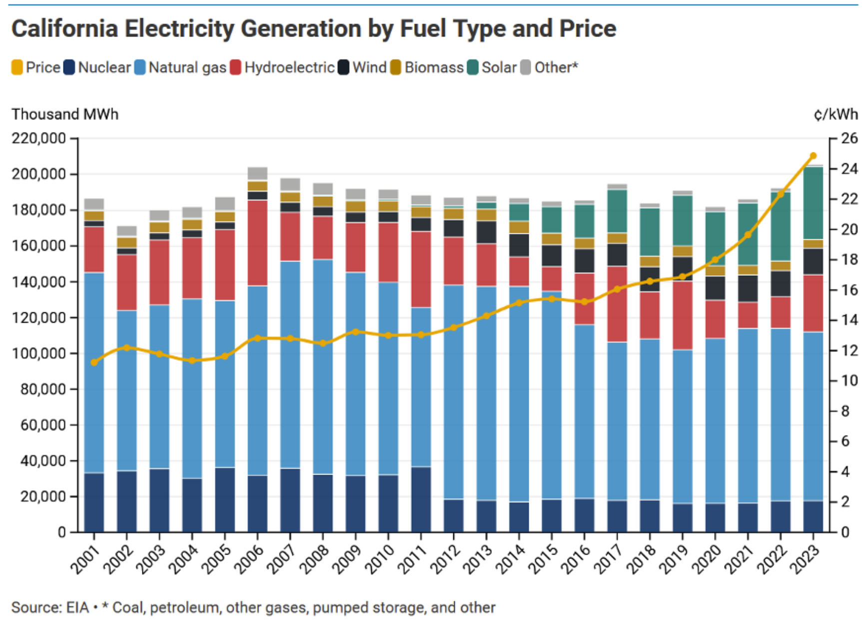
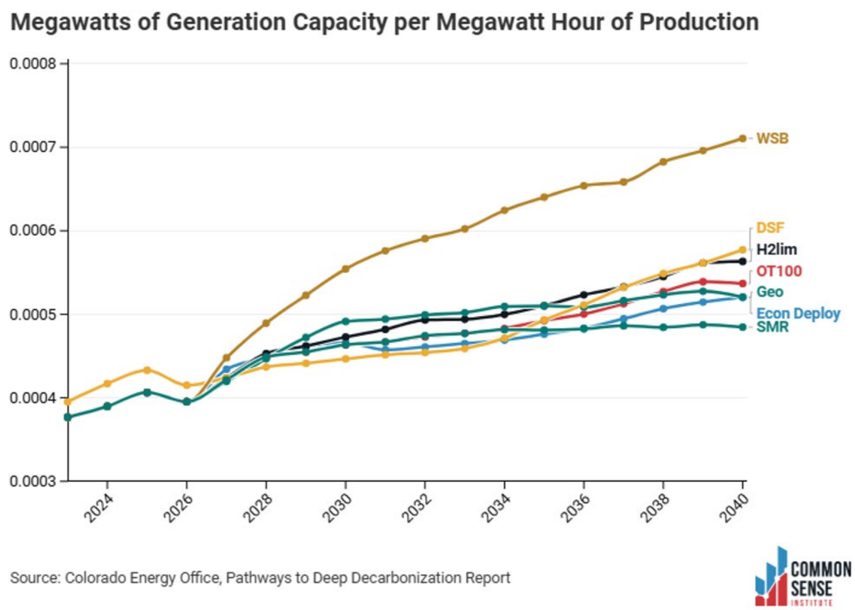


FIGURE 22



the spot market. This unhealthy demand dynamic results in short-term price spikes and extreme volatility in natural gas prices during a weather-driven crisis. This directly leads to higher utility bills for consumers. Other technologies or fuel sources, such as existing coal capacity, could provide a more reliable baseload and avoid this volatility. However other baseload fuels were not considered in the scenario, and coal is being phased out by 2031.

FIGURE 23



THE BOTTOM LINE

Colorado's electricity prices are projected to rise significantly in the coming years, driven by sweeping changes in power generation as outlined in the state's *Pathways Report*. These changes include substantial investments in wind, solar, and battery storage, alongside the early retirement of coal and natural gas plants. The resulting higher electricity prices will have far-reaching economic consequences, placing increased financial strain on households, businesses, and individual Coloradans.

Additionally, considerable uncertainty surrounds the operational costs of newer energy technologies. Combined with known costs omitted from the *Pathways Report*, namely increased levels of transmission and distribution investments, actual electricity prices are likely to exceed projections in this report, making the cost projections conservative.

As Colorado moves forward, policymakers and the public must carefully weigh these pending price impacts. Future policies should balance the costs of reducing greenhouse gas emissions in the state against the financial burdens placed on individual households, while considering the broader context of global CO2 emissions. Thoughtful, data-driven decision-making and high degrees of transparency will be critical to ensure that Colorado achieves its environmental goals without undermining economic resilience or household budgets.

APPENDIX A

Colorado Energy Office Pathways Report

Colorado's rapidly changing energy landscape means there will be significant financial resources deployed in the coming years to meet the state's emission reduction goals. The growth in new electricity resources will be coupled with the removal of existing plants that have remaining productive life. Some of the costs of these changes are detailed in a report released earlier this year titled "Pathways to Deep Decarbonization in Colorado's Electric Sector by 2040; An Analysis of Colorado's Energy System in Meeting the State's Clean Energy Goals." Released spring 2024 the report was commissioned by the Colorado Energy Office (CEO) and developed by Ascend Analytics.[v]

The Colorado Energy Office worked closely with Ascend Analytics to develop seven scenarios for the future capacity and generation of Colorado's electric power sector.

CURRENT POLICY BASELINE

- **Economic Deployment Scenario** – This scenario is the current policy baseline described as including "current electric utility resource plans and the trajectory for greenhouse gas (GHG) reductions under those plans." The scenario "also includes current state and federal policies" and "meets the same projected 2040 electricity need as other scenarios and is the lowest cost path to deep decarbonization."

100% GREENHOUSE GAS EMISSION REDUCTION SCENARIOS

- **Optimized 100 (OT100)** – "A cost-optimized scenario required to meet zero-carbon emission by 2040 target, that could choose from all technology options. It is the most efficient pathway to a carbon free grid in 2040."

- **Wind, Solar, and Battery only (WSB)** – "The model was only allowed to select wind, solar, and batteries to meet the zero-carbon emissions requirement."

- **Accelerated Geothermal Adoption (GEO)** – "The scenario is required to use geothermal to meet at least a certain percentage of electric capacity needed by particular years – 2% in 2034, 4% in 2036, 8% in 2038, and 10% in 2040. The model selected other resources to meet a 2040 zero emissions target on a cost-optimized basis."

- **Distribution-System Level Focus (DSF)** – "This scenario focused on meeting state electricity needs with customer-sited, distribution level resources. Because of that, the scenario assumes higher amounts of grid interconnected distributed energy resources (DERs), vehicle-to-grid participation by EV owners, demand response, beneficial electrification, and energy efficiency to model the impacts on the grid and bulk system resources than the other scenarios."

- **Small modular reactors (SMR)** – "This scenario builds out small modular nuclear reactors in the late 2030s: two 320 MW reactors are built each year from 2035- 2040, spread across the state. The model is allowed to select other resources to meet a 2040 zero emissions target on an economic basis."

- **Hydrogen Limited (H2lim)** – "This is a sensitivity of the Optimized 100 scenario. This scenario limits the model's use of hydrogen to evaluate which resources could potentially replace hydrogen if hydrogen was unavailable at the levels shown in the Optimized 100 scenario."

Ascend Analytics ran each scenario in their software model PowerSIMM, customized for the Colorado electric grid. The full *Pathways Report* includes more details on model inputs and assumptions, producing results across several key dimensions.

- Electric sector capacity by resource including retirements and new additions.

- Electric sector generation by resource.

- Costs of new capacity additions and annual operation and maintenance.

While there are many underlying data inputs and modeling assumptions, there are several critical ones to understand the results of the *Pathways Report* in the proper context.

- **Demand** – Each scenario relied on very similar demand projections with the exception of the Demand Side Management scenario. Therefore, regardless of cost to the user, the model assumed that the demand for electricity would be roughly the same under each scenario. It includes an aggressive load growth assumption given the expectation that electricity demand growth outpaces general population and economic factors. This is due primarily to policy assumptions around buildings and vehicles switching from other fuel sources to electricity over the next several decades.

- **Policy baseline vs technology baseline -** The baseline in the Pathways Report, titled the Economic Deployment Scenario, is constructed to meet state policy requiring large emission reductions from electric power generation sector. It is not a baseline that was developed strictly based on cost and reliability. Therefore, while the report compares costs between 6 alternative scenarios and the Economic Deployment Baseline, the report does not estimate what the system costs would be without state policy goals.

FIGURE 24

Colorado Electric Sector Capacity and Generation - Pathways Report Baseline - Economic Deployment Scenario Values in Megawatts (excludes imports)												
	2023				2030				2040			
	Capacity		Generation		Capacity		Generation		Capacity		Generation	
	#	%	#	%	#	%	#	%	#	%	#	%
Wind	5443	25%	14.51	25.1%	9326	27%	30.40	41%	10654	22%	34.49	37%
Solar PV	2160	10%	5.52	9.5%	7022	20%	18.54	25%	12059	25%	32.75	35%
Biomass	34	0%	0.20	0.3%	53	0%	0.31	0%	53	0%	0.31	0%
Hydro	676	3%	1.76	3.0%	676	2%	1.76	2%	676	1%	1.76	2%
Oil	180	1%	0.06	0.1%	13	0%	0.04	0%	0	0%	0.00	0%
Natural Gas	7769	36%	14.00	24.2%	8848	26%	2.64	4%	8215	17%	1.77	2%
Coal	4200	19%	9.51	16.4%	857	2%	3.72	5%	0	0%	0.00	0%
Gas w/CCUS	0	0%	0.00	0.0%	0	0%	0.00	0%	0	0%	0.00	0%
Nuclear	0	0%	0.00	0.0%	0	0%	0.00	0%	0	0%	0.00	0%
Geothermal	0	0%	0.00	0.0%	0	0%	0.00	0%	0	0%	0.00	0%
Hydrogen Thermal	0	0%	0.00	0.0%	0	0%	0.00	0%	0	0%	0.00	0%
V2G	0	0%	0.00	0.0%	207	1%	-0.25	0%	2149	4%	-2.33	-2%
4-hr Li-Ion Battery	265	1%	-0.05	-0.1%	2956	9%	-0.47	-1%	6051	12%	-0.67	-1%
12-hr Battery	0	0%	0.00	0.0%	800	2%	-0.26	0%	3147	6%	-0.75	-1%
100-hr Iron-Air Battery	0	0%	0.00	0.0%	0	0%	0.00	0%	0	0%	0.00	0%
Pumped Hydro Storage	509	2%	-0.46	-0.8%	509	1%	-0.56	-1%	509	1%	-0.46	0%
Demand Response	452	2%	0.03	0.1%	858	2%	0.07	0%	1233	3%	0.10	0%
Distributed Solar PV	122	1%	0.17	0.3%	2276	7%	3.13	4%	3833	8%	5.34	6%
Distributed 2-hr Li-Ion Battery	6	0%	0.00	0.0%	120	0%	-0.02	0%	202	0%	-0.03	0%

FIGURE 25

Nominal Cost of Capital + OM per kWh								
	Economic Deployment Scenario Load(tWh) minus imports	Econ Deploy	OT100	H2lim	Geo	DSF	WSB	SMR
2023	45.82	$0.079	$0.079	$0.079	$0.079	$0.087	$0.079	$0.071
2024	59.01	$0.072	$0.072	$0.072	$0.072	$0.086	$0.072	$0.059
2025	56.56	$0.072	$0.072	$0.072	$0.072	$0.084	$0.072	$0.072
2026	58.06	$0.068	$0.068	$0.068	$0.068	$0.081	$0.068	$0.068
2027	65.22	$0.091	$0.143	$0.148	$0.130	$0.073	$0.108	$0.142
2028	62.90	$0.066	$0.096	$0.102	$0.094	$0.093	$0.108	$0.096
2029	61.10	$0.072	$0.063	$0.071	$0.091	$0.073	$0.108	$0.063
2030	60.62	$0.059	$0.068	$0.074	$0.089	$0.077	$0.109	$0.068
2031	59.97	$0.042	$0.064	$0.074	$0.069	$0.078	$0.108	$0.063
2032	61.39	$0.041	$0.058	$0.068	$0.063	$0.059	$0.084	$0.060
2033	62.61	$0.040	$0.045	$0.045	$0.049	$0.050	$0.074	$0.043
2034	64.58	$0.040	$0.045	$0.048	$0.054	$0.062	$0.083	$0.043
2035	66.38	$0.041	$0.082	$0.084	$0.076	$0.093	$0.102	$0.134
2036	68.21	$0.042	$0.059	$0.068	$0.050	$0.086	$0.081	$0.114
2037	70.18	$0.045	$0.084	$0.081	$0.083	$0.099	$0.086	$0.141
2038	72.46	$0.048	$0.092	$0.091	$0.093	$0.100	$0.119	$0.144
2039	74.40	$0.050	$0.063	$0.071	$0.092	$0.066	$0.090	$0.130
2040	76.55	$0.042	$0.049	$0.064	$0.086	$0.091	$0.099	$0.132

The first two columns in Figure 26 show the nominal and inflation adjusted costs for each scenario. The third column shows the reported net present value (NPV) costs, assuming a 6% discount rate. The inflation adjusted costs convert the nominal costs into 2023 dollars.

FIGURE 26

Cost Of Capital and Operation and Maintenance By Scenario 2023-2040			
Scenario	Nominal	Real $2023	NPV (6% Discount Rate)
Econ Deploy	$67,597,395,426	$56,067,558,485	$43,063,883,383
OT100	$85,606,042,891	$70,439,108,816	$51,628,137,044
H2lim	$90,797,642,481	$74,514,391,118	$54,107,366,921
Geo	$93,211,838,725	$76,045,377,207	$54,673,175,347
DSF	$95,702,036,793	$77,664,956,861	$56,111,674,643
WSB	$109,339,310,278	$88,491,660,377	$60,973,975,653
SMR	$110,900,991,559	$88,121,603,004	$60,832,613,242

The costs range from $67.6 billion to $110.9 billion over an 18-year period. The reported cost of capital and operation and maintenance (O&M) costs do not include additional expenses that utilities incur such as return on equity, debt financing, and taxes. These additional expenses, in combination with the nominal costs, will be spread over decades as utilities recover the costs through ratepayers. And, given these costs do not include new transmission or distribution costs, it can be assumed that these costs are much lower than what reality will be, especially given how aggressive wind and solar additions are in the scenarios.

Figure 27 shows the total cost between 2023 and 2040 divided by the electric load produced within Colorado. The total electric load produced within Colorado is the total load less imports as reported in the *Pathways Report*. Total capex divided by total load generation results in cents per kWh. As shown, the total costs per kWh range from 4.58 cents/kWh to 6.35 cents/kWh.

FIGURE 27

Total Capital + O&M Costs Per Total kWh Generated 2023-2040	
Econ Deployment	$0.0458
OT100	$0.0509
H2lim	$0.0528
Geo	$0.0544
DSF	$0.0579
WSB	$0.0593
SMR	$0.0635

Missing Costs from CEO Report

The total costs in the Economic Deployment scenario are less than half of the current costs of electricity on a kWh basis. In the Economic Deployment scenario costs are less than 5 cents a kWh but current electricity prices are above 12 cents. Therefore, there are costs not accounted for in the modeled results that the consumer bears.

- **Full transmission and distribution investments** – The *Pathways Report* states “transmission upgrades necessary to integrate the high levels of wind and solar generation into the grid were not included in the cost analysis. This study focused on generation supply and did not include detailed information on transmission or distribution aspects of the Colorado electric grid.” It is well known that transmission costs associated with wind and solar power additions are significant and can be prohibitively expensive, as seen in Germany, the UK, and China. The investment needed to add new transmission and distribution would be in addition to the projected prices in this report.

- **Operational costs associated with a larger share of intermittent sources** – Though the modeling includes two reliability requirements, both a maximum outage of 0.1 hours in any given year and a 15% capacity reserve margin, it does not specify how an increase of shorter disruptions produce increased costs across the system. The scenarios assume the ability to import electricity during times of outages, which raises questions about whether that would be feasible during weather-related outages when other states will also be demanding that power.

- **Costs associated with operating natural gas power generation at very low capacity factors** – The *Pathways Report* suggests that natural gas will serve as critical firm capacity and backup power generation in the Economic Deployment scenario, but will only "operate a few hours a year." It is unclear if this estimate includes the costs associated with maintaining and operating natural gas generation at such low rates. Natural gas power generation is often designed to be run at full capacity to ensure efficiency and get the benefits of emission reduction from such efficiency. This model likely does not account for greater emissions from inefficiently utilizing natural gas power.

Colorado Public Utilities Commission Concentric Energy Advisors Model

The energy consulting firm Concentric Energy Advisors developed an electric rate forecasting model for the Colorado Public Utilities Commission, also released in 2024. This model referred to as the '30 Year Rate Model' includes the latest investment and operation and maintenance costs at the time of its release, based on utility resource plans for the Public Service Company of Colorado (PSCo) region. It shows rates increasing from $0.09 per kWh to $0.12 per kWh over 12 years, between 2011 and 2023. By 2030 the model projects prices increase to $0.17 kWh. If prices kept pace with an inflation trend of 2.5%, they would only be $0.14 kWh. This means the projected price is 8 cents more than the baseline of 9 cents Colorado experienced for the better part of a decade prior to 2021.

Methodology to Model Electricity Prices

The '30 Year Rate Model' developed by Concentric Energy Advisors for the Colorado Public Utility Commission can be modified to estimate alternative rate impacts to the Public Service Company (PSCo) electricity service region.

- **Allocation of share of PSCo region** – According to EIA electricity sales data, 50.5% of all 2023 statewide electricity sales occurred within the PSCo territory. This share was applied to the capital and O&M capital costs in the *Pathways Report*, along with the sales volume.

- **Change to new capital production and O&M revenue requirements** – The original values included in the 30-Year Rate Model for capital expenditures on new production and O&M were changed to reflect values given by the *Pathways Report* Economic Deployment baseline. Each single-year capital expenditure was multiplied by an annual revenue requirement share, estimated by Concentric Energy Advisors.

- **Change to baseline sales volume** – The *Pathways Report* sales forecast was used to replace the original 30-Year Rate Model sales to align the report's expenses with its projected demand.

- **Removal of fuel and purchased energy revenue requirements** – Given the *Pathways Report* O&M values include fuel costs, the model's original values were zeroed out for these categories.

The rate projections under the cost assumption in the *Pathways Report* show that rates grow faster in earlier years, and then slightly slower approaching 2040 relative to the '30 yr Rate Model' baseline. This is due to a larger estimate of capital costs in earlier years in the *Pathways Report.*

REMI Model Inputs

Direct costs to each consumer group were derived by taking the difference in electricity prices per kWh for each year in the Projected Rate scenario and Inflation Rate Trend scenario. The per kilowatt hour difference was then multiplied by the number of customers reported by EIA. The number of annual customers was held constant to provide a conservative estimate of the total costs.

FIGURE 28

Projected Direct Costs to Consumer Sectors of Electricity Outpacing Inflation - REMI Inputs			
	Households	Commercial	Industrial
2024	$33,170,136	$33,919,868	$24,189,624
2025	$534,244,855	$546,320,187	$389,602,932
2026	$422,167,337	$431,709,424	$307,869,380
2027	$299,671,968	$306,445,339	$218,538,515
2028	$521,389,962	$533,174,740	$380,228,384
2029	$793,043,620	$810,968,482	$578,334,292
2030	$966,108,419	$987,944,998	$704,543,374
2031	$1,021,132,467	$1,044,212,734	$744,670,163
2032	$1,067,156,786	$1,091,277,323	$778,233,818
2033	$1,124,870,028	$1,150,295,036	$820,321,726
2034	$1,103,158,068	$1,128,092,328	$804,488,081
2035	$1,133,929,002	$1,159,558,766	$826,928,065
2036	$1,255,357,233	$1,283,731,593	$915,480,710
2037	$1,361,972,234	$1,392,756,372	$993,230,672
2038	$1,432,362,377	$1,464,737,516	$1,044,563,325
2039	$1,406,464,342	$1,438,254,118	$1,025,676,947
2040	$1,457,156,251	$1,490,091,796	$1,062,644,484

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