The Future of Energy Storage in Colorado

Opportunities, Barriers, Analysis, and Policy Recommendations

Prepared for the Colorado Energy Office

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CONTENTS

EXECUTIVE SUMMARY

On behalf of the Colorado Energy Office, Synapse Energy Economics, Inc (Synapse) conducted a modeling and research exercise focused on the expansion of energy storage in the State of Colorado. Specifically, Synapse explored the role of energy storage in Colorado's energy policy future and the benefits it can provide to the state. The research component of the project focused on assessing the landscape of commercially available energy storage technologies, the services energy storage can provide to the grid, barriers to deploying energy storage at scale, and best practices in policies that enable energy storage across the United States. The modeling component of the project first assessed the potential deployment of both utility-scale and residential behind-the-meter (BTM) energy storage under different policy scenarios between 2019 and 2029. Second, we translated the potential deployment of utility-scale energy storage into economic impacts for the state, including employment, average individual income, and Gross Domestic Product (GDP).

The Colorado state government is acting to reduce emissions in the electric sector and increase the quantity of renewable energy on the grid. Specifically, Governor Polis recently committed the state to a goal of 100 percent carbon-free electricity by 2040. In parallel, Colorado's largest investor-owned utility (IOU)—Xcel Energy[1]—is planning to retire several coal plants and replace the energy and capacity with renewables and energy storage. As the state electricity grid transitions towards a high renewable-energy future, there is an increasing need for energy storage to serve peak demand needs. In addition to meeting peak demand with renewable generation, energy storage can provide many other types of valuable grid services. These include frequency regulation, voltage support, energy reserves, energy arbitrage, and deferral of transmission and distribution infrastructure investment. Though pumped hydro is currently the most prevalent type of energy storage in the United States, traditional battery storage technologies (primarily lithium-ion) have experienced rapid market growth within the last few years. As costs continue to decline in the coming decade, flow batteries are also expected to become common in large-scale storage applications.

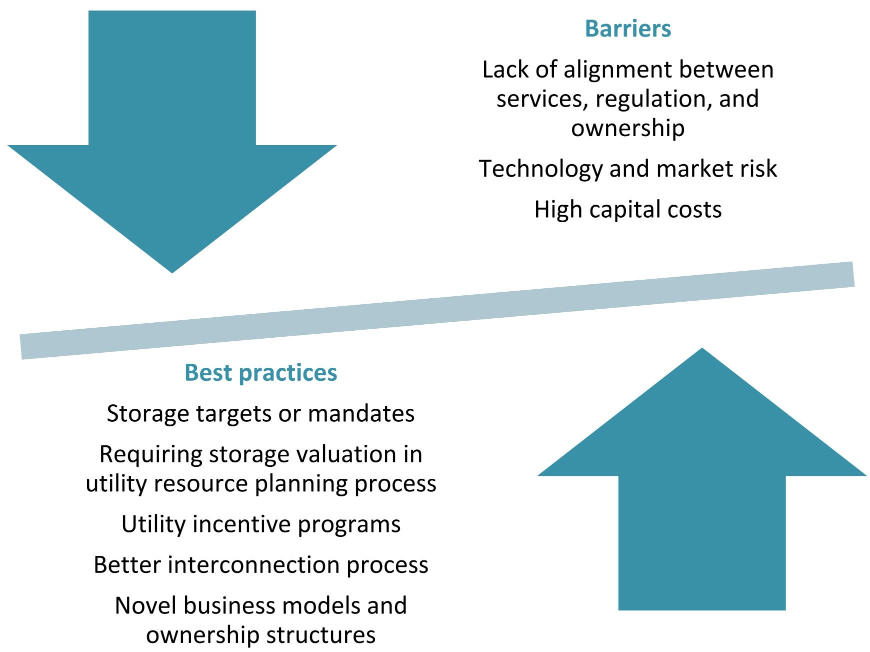
Many of the services that energy storage can provide are represented in wholesale markets, which provide a transparent process to identify the value that resources provide. These services include energy, capacity, and ancillary services. Colorado does not participate in a wholesale market under the jurisdiction of the Federal Energy Regulatory Commission (FERC); therefore, state policymakers, regulators, and utility decision-makers cannot rely directly on markets for transparent valuation metrics. However, stakeholders can look to wholesale markets elsewhere to understand how energy storage demonstrates its value and how that value is quantified. This insight can inform their evaluation for in-state decisions.

The specific barriers that energy storage experiences in Colorado include: a lack of alignment between services, regulation, and ownership; technology and market risk; and high capital costs. To address these

[1] Xcel Energy is also referred to as the Public Service Company of Colorado.

barriers, states leading the deployment of energy storage in the United States are: enacting storage targets or mandates; requiring storage to be considered during the utility resource planning process via a structured valuation process; implementing utility incentive programs; simplifying and clarifying the interconnection process for storage; and creating novel business models and ownership structures. Colorado is in a particularly opportune time to explore some of these options. As of this writing, Colorado is revising its overall Electric Resource Planning rules in proceeding number 19R-0096E.

Figure 1. Barriers and best practices to energy storage deployment



Grid-Modeling Overview

To develop the storage policy recommendations developed in this report, Synapse engaged in a rigorous modeling exercise to evaluate the future role and benefits of energy storage under a Reference Case, a Carbon Price Case, and two policy scenarios in Colorado for the 2019-2029 timeframe. The policy scenarios we modeled represent different strategies that the State of Colorado may undertake in the near term:

- The Reference Case represents a future in Colorado without the passing of the Sunset Bill (SB 19-236) and the associated utility resource-planning carbon price. This scenario is included to illustrate the impact of the Sunset Bill on Colorado's energy future.
- The Carbon Price Case represents "business as usual" in Colorado. This Case includes the utility resource-planning carbon price that was recently passed in the Sunset Bill (SB 19-236). The price starts at $46/short ton in 2020 and escalates by 2 percent per year throughout the study period. This Case also assumes that Colorado will not expand its

Renewable Energy Standard (RES) and existing RES requirements will remain in place through 2029.

- The Coop Scenario includes the Sunset Bill's resource-planning carbon price. In addition, this Scenario assumes that the self-generation limit on electric cooperatives enforced by the contract with Tri-State G&T would be relaxed by 1 percent each year starting in 2020, resulting in a self-generation limit of 15 percent by 2029. The model assumes that any self-generation by the cooperatives will be met with solar PV, battery storage, or paired solar-plus-storage resources.

- The RES Scenario includes the Sunset Bill's resource-planning carbon price. In addition, this Scenario assumes that Colorado's RES requirements increase after 2020. For IOUs, the RES will require that 75 percent of total electricity sales come from RES-eligible technologies by 2029. Similarly, for municipalities and cooperatives, the RES requirement will increase to 30 percent of total sales by 2029. Although storage is not currently an eligible technology to meet the Colorado RES, this scenario assumes that generation from paired storage resources can meet the RES requirement.

The following summary describes the results of our modeling from all four scenarios:

- The Sunset Bill's resource-planning carbon price is expected to be responsible for a cumulative reduction of 40 million short tons of carbon dioxide from 2019–2029.[2]

- The role of battery storage in the state is expected to be minimal and concentrated in the later years of the study period, from 2026 onward.

- The limited build-out of batteries prior to 2026 is due to high capital and operating costs relative to other traditional generators in the early years of the study period.

- Generation and capacity by resource type in the Coop Scenario are very similar to the Carbon Price Case. However, the Carbon Price Case does have a slightly larger battery storage buildout than the Coop Scenario.

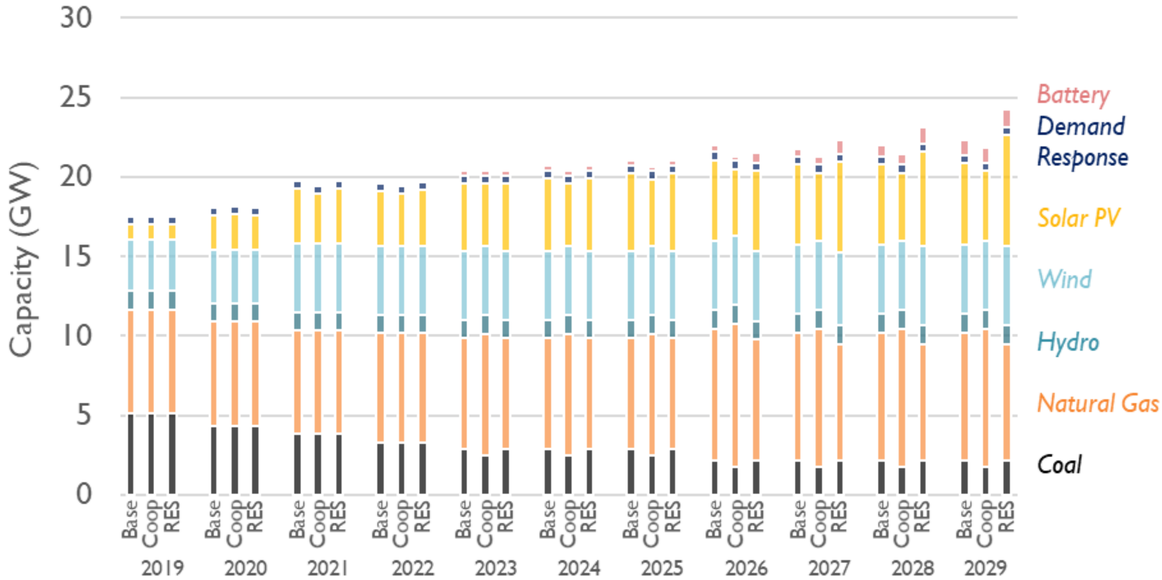
- Battery storage capacity build-out and generation levels are highest in the RES Scenario, though only marginally, resulting in a total of 1.1 GW of battery capacity and 1.9 GWh of battery generation in 2029 (Figure 2).

- In the RES Scenario in 2029, battery storage technologies are expected to provide 7 percent of Colorado's incremental energy since 2019, but only 2 percent of Colorado's total annual generation.

- From 2019 to 2029, net average annual employment impacts amount to an increase of approximately 1,000 average annual jobs under the RES scenario and a decrease of 440 average annual jobs under the Coop scenario (Figure 3).

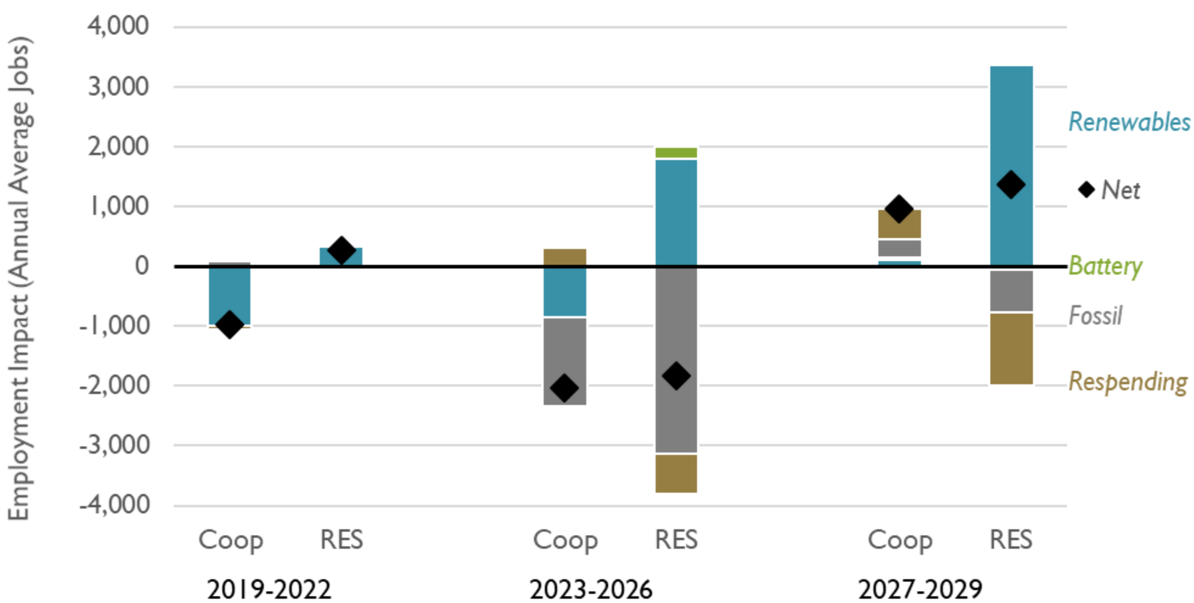
[2] This impact is also due to the assumption that there are no minimum capacity factor requirements for coal units (coal "must-runs") in the Carbon Price Case.

Figure 2. Total installed capacity by resource type in Colorado across scenarios, 2019–2029



Note: The Reference Case is not included in this figure, as it is included later in the report when compared only to the Carbon Price Case. Source: Synapse calculations based on EnCompass outputs.

Figure 3. Average annual employment impacts of Coop and RES scenarios relative to Carbon Price Case



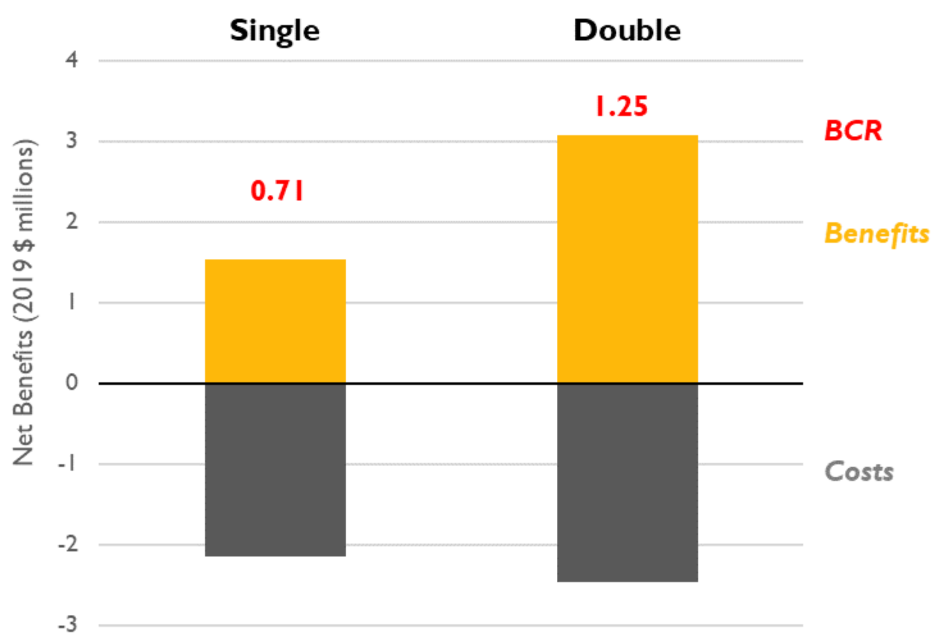
Source: Synapse calculations.

Behind-the-Meter Modeling Overview

Synapse developed a custom-built spreadsheet model to evaluate the costs and benefits of BTM storage technologies offered to residential customers in Colorado. We used the parameters of Xcel Energy's Residential Battery Demand Response Program as our default model inputs. Though Xcel's program is planning to incentivize customers to adopt a single 5 kW battery system, we also modeled a two-battery alternate pilot to compare the incremental costs and benefits. In the first year of the program, Xcel expects 250 residential participants, followed by an additional 250 participants in the second year of the program. While the pilot program is only planned for two years, we calculated the lifetime costs and benefits over a 10-year period. We analyzed the impacts of avoided energy, capacity, transmission, and distribution costs due to the battery program.

Our analysis found the double-battery scenario to be cost-effective, but not the single-battery scenario. Figure 4 illustrates the benefit-cost ratio (BCR) of single- and double-battery systems; a BCR over 1.0 implies that the program is cost-effective. A participant supplying a single battery would not be able to provide enough capacity to cover the utility's program costs and incentives. Therefore, a minimum of two batteries should be a requirement for program participation, and incentives should be adjusted to encourage a double-battery system.

Figure 4. Benefits, costs, and benefit-cost ratio (BCR) of a single- vs double-battery system



Source: Synapse calculations.

Recommendations

As evidenced by the results of the grid-level modeling, the development of energy storage in Colorado is likely to ramp up slowly in the coming decade without the presence of smart energy policy. The absence of a stable revenue stream to compensate energy storage for the many services it provides to the grid creates an environment of uncertainty for developers. This limits the development of a robust and competitive battery storage market in the state that will be required to drive down capital costs and increase adoption. Though lithium-ion battery costs are projected to decline in the coming years, there is debate about whether they are expected to become cost-competitive with traditional generators prior to the late 2020s without supportive policy mechanisms.

Despite the technology's challenges with economic competitiveness in the early years, storage provides long-term system benefits that have not typically been incorporated into utility planning processes. These benefits are increasingly important as Colorado transitions to an electric grid supplied primarily with variable renewable energy resources. Without properly evaluating these benefits, utilities and developers will risk unnecessary investment in infrastructure projects over the long term.

As such, Synapse recommends the following pathways to help encourage an earlier and deeper penetration of energy storage in Colorado:

1. Track development of the storage market to determine the necessity of an energy storage target or mandate in Colorado.
2. Develop a stable, transparent storage valuation protocol for utility resource planning based on best practices in leading states and wholesale markets.
3. Establish a process to identify and screen for opportunities for non-wires alternatives (including energy storage and other distributed energy resources) to meet load growth and reliability objectives.
4. Support innovation in storage ownership business models.
5. Continue to revise interconnection and planning processes to incorporate lessons learned from storage procurement and deployment.

In conjunction with the current Electric Resource Planning proceeding in Colorado, the above policy mechanisms are likely to reduce the barriers to storage deployment, thereby bolstering the state's transition to a renewable, carbon-free electric grid.

1. INTRODUCTION

In 2016, Colorado's electric generation was sourced primarily from coal (46 percent), followed by natural gas (20 percent) and renewable energy (34 percent).[3] The Colorado state government is acting to reduce emissions in the electric sector and increase the quantity of renewable energy on the grid. Specifically, Governor Polis recently committed the state to a goal of 100 percent carbon-free electricity by 2040. In parallel, Colorado's largest investor-owned utility (IOU)—Xcel Energy—is planning to retire several coal plants and replace the energy and capacity with renewables and energy storage.

As the state's electricity grid transitions towards a high renewable energy future, there is an increasing need for energy storage to serve peak demand. Energy storage allows electricity from renewable resources like wind and solar, whose generation does not always match temporally with peak electricity consumption, to be stored and used later when energy is in higher demand. In addition to providing energy for peak load, energy storage can provide many other grid-supportive services (e.g. frequency regulation, voltage support, reserves). Though there are several types of energy storage technologies commercially available, the most prevalent installed technology is pumped hydro. Colorado is home to a single 336 MW pumped hydro facility at the Cabin Creek Generating Station. Though less prevalent, the lithium-ion battery is the most promising technology type for the near term due to declining costs and increasing performance.

Colorado is home to two existing large-scale lithium-ion battery installations—a 1 MW and a 4 MW installation. As part of Xcel Energy's most recent Electric Resource Plan (ERP), two coal units at Comanche Generating Station will be replaced with a combination of renewables and 275 MW of energy storage.[4] Battery storage capacity is also increasing regionally. For example, Tuscon Electric recently signed a contract with NextEra for a 100 MW solar farm with 30 MW of 4-hour battery storage. Similarly, NV Energy filed a resource plan that includes more than 1,000 MW of solar paired with 100 MW of 4-hour battery storage.

To facilitate the adoption of additional energy storage in Colorado, the state legislature recently passed House Bill 18-1270, the Energy Storage Procurement Act. The resulting rules, as stipulated by the Colorado Public Utilities Commission, require consideration of energy storage in utility ERPs, including documentation of the methodology and assumptions used to evaluate energy storage as a resource option.[5] Utilities are also required to propose how energy storage systems smaller than 30 MW can be

[3] U.S. Energy Information Administration, State Energy Data System (SEDS) 1960-2016: https://www.eia.gov/state/seds/seds-data-complete.php?sid=CO

[4] Xcel solicited bids for renewables plus 4-hour battery storage. The median solar-plus-storage bid was $36 per MWh and the median wind-plus-storage bid was $21 per MWh. Xcel estimates that the replacement of coal with renewables plus storage will save ratepayers between $213 and $374 million.

[5] Colorado PUC, 723-3 Electric Rules, accessible via https://www.colorado.gov/pacific/dora/electricrules/.

acquired in all-source competitive procurements. As of this writing, Colorado is also revising its overall ERP rules in proceeding number 19R-0096E.

Given the state's keen interest in the deployment of energy storage, the Colorado Energy Office hired Synapse Energy Economics to conduct a research and modeling exercise focused on the barriers and opportunities for storage in Colorado from the present through 2029.

The goals of this report include the following:

- Describe the types of available commercial energy storage technologies, their individual strengths, and the grid-supportive services that each can provide (Section 2)
- Discuss barriers and best practices around energy storage policy and regulation in the United States (Section 3)
- Use electric system modeling and economic impacts modeling to determine the potential value of storage to Colorado over the next decade (Section 4)
- Provide recommendations for Colorado to increase the role of energy storage in the state's energy portfolio (Section 3.4)

2. TECHNOLOGY ASSESSMENTS

Grid-connected electric energy storage can take many forms and provide a wide range of services to the grid. The many forms of energy storage are usually best suited for a specific set of applications or services to the grid. This section starts by describing the services that energy storage can provide to the grid, then addresses each of the most common technologies for storage and discusses their advantages and disadvantages with respect to delivering different services.

2.1. Services

Energy storage can provide services to the distribution and transmission systems, as well as aid the efficient functioning of power supply dispatch. Deployed storage systems can provide services at timescales ranging from milliseconds to hours. In some cases, these services depend on quick response (the ability to change the input or output power of the storage system quickly) while in other cases they depend on the duration of the storage (how long the storage system can provide power at its maximum level). This section describes six services that energy storage can provide to the grid, ordered from the fastest response to the longest duration.[6]

[6] We have focused this analysis on services to the electric grid. Distributed storage systems deployed BTM by customers can contribute to these grid services, while also providing other services, such as uninterruptible power or demand charge

Frequency Regulation

Grid operators need to match supply and demand on a moment-by-moment basis to ensure the stability of the grid. When demand exceeds supply, the frequency on the grid drops below its standard value (60 Hz in the United States); when supply exceeds demand, the frequency rises. Frequency regulation is a fast-response service that maintains this balance on the grid.[7] Generation resources can provide frequency regulation service by rapidly changing their output in response to a signal from the grid operator. Energy storage is well suited to frequency regulation service because it can change direction (charging to discharging, or vice versa) very quickly. Some energy storage technologies can also provide even faster "frequency response" services, where they charge or discharge in response to immediate measurements of the frequency, rather than waiting for a dispatch signal from the grid operator. Frequency regulation does not require a long-duration storage technology because the grid operator's signal can be designed to net to zero over periods of minutes. For this reason, a typical storage system designed for frequency regulation service might have a duration of 15 minutes at peak input or output; longer-duration storage can also provide this service.

While Colorado is not in an organized electricity market, the two balancing authorities for Colorado—the Western Area Power Administration, Colorado-Missouri Region (WACM) and Xcel Energy in Colorado—have some need for regulation service that could be provided by storage technologies. As variable renewable energy penetration increases in the state, frequency regulation service may play an important role in integrating these resources.

Voltage Support

In addition to keeping frequency at the required level, grid operators must also keep voltage and current aligned in order to maximize the power available on the grid (Figure 5).[8] When voltage and current are out of alignment, utilities can make adjustments on a *static* basis, but those adjustments may be inadequate if the load shifts causing the misalignment are *dynamic*. Energy storage systems include power electronics components that can re-align voltage and current *dynamically*.

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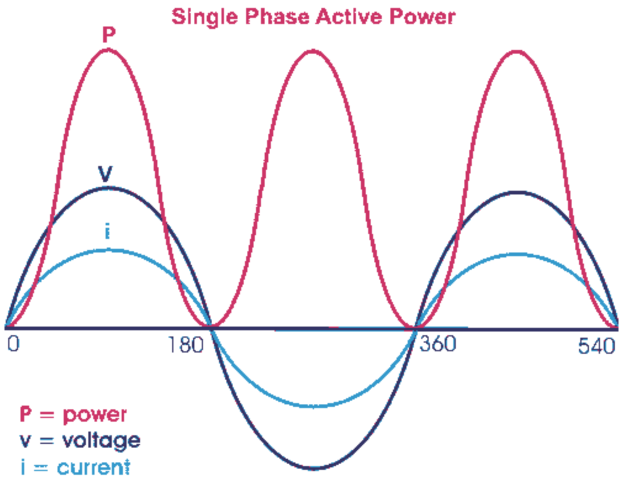
mitigation, to their site hosts. *The Economics of Battery Energy Storage* by Rocky Mountain Institute summarizes the value that storage can provide in these and other services; see https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf.

[7] See https://www.e-education.psu.edu/ebf483/node/705 from the Penn State e-education course "Introduction to Electricity Markets" for a primer on frequency regulation.

[8] Voltage and current can get out of alignment due to inductive loads (like motors, which make the current lag the voltage) or capacitive loads (like long cable runs, which make the voltage lag the current).

Figure 5. The waveform of alternating current, showing optimal alignment between voltage (v) and current (i), leading to maximized power (P)



Source: "Electric Power Single and Three Phase Power Active Reactive Apparent" from Electrical 4 U, available at https://www.electrical4u.com/electric-power-single-and-three-phase/.

Because voltage alignment conditions are localized, they are difficult to address with resources located at substations or further upstream from customers' loads. Long distribution feeders, which commonly exist in rural areas, often require voltage support—especially if the feeders are also home to variable distributed generation resources. Energy storage that is located on distribution feeders can provide voltage support in real time to improve power quality. It would be unusual to design an energy storage system primarily to provide voltage support, but energy storage systems of any duration can generally provide this service as part of their suite of services if they are located in a place where it is valuable.

Reserves

Reserves are resources available to provide power to the grid on short notice in case generators or transmission lines go offline.[9] Utilities that provide generation, such as Colorado's vertically integrated utilities or the generation providers that serve the state's smaller utilities, must maintain adequate reserves for reliability in the event that power becomes unavailable. Reserves are divided into two types based on how fast they can respond: spinning and non-spinning. Spinning reserves are available at a moment's notice and may also be providing frequency regulation service. For example, a generator or storage system that is online and providing power may be outputting at one level, then ramp up to a higher steady state level quickly at the utility's signal to provide reserves. Non-spinning reserves are generators able to come online within 10 minutes. Energy storage can respond quickly so it can

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[9] The North America Electric Reliability Corporation maintains a summary of the ancillary service structures, including reserves, used by each North American electric market at https://www.nerc.com/docs/pc/ivgtf/NERC_ancillary_services%20ERCOT%20IESO%20NYISO%20MISO%20PJM%20SPP%20WECC%2012%2014.pdf.

contribute to spinning reserves to the extent that it remains charged. A storage system can provide reserves if its duration exceeds the time necessary for slower generators to respond (typically half an hour but it depends on the configuration of the utility's generation mix) or the offline generator to be restored.

Resource Adequacy/Capacity

Resource adequacy, or capacity, is the service of providing power needed to meet peak loads.[10] Typically, these peaks occur on the coldest winter days or hottest summer days and are driven by heating or cooling demands. In Colorado, the highest peak of the year is experienced during the summer. Capacity resources must be able to provide power to the grid for the duration of the peak event, generally a few hours. Traditionally, capacity-focused generation resources are combustion turbines or reciprocating engines—systems with relatively low capital costs that can sit idle and wait to deliver during peak times. Energy storage can also help to meet capacity needs by promising the grid operator to be charged and ready to deliver during peak events. This service will become increasingly important as Colorado increases the amount of variable renewable resources on its electricity grid.

Energy Arbitrage

Different types of generators have different operating costs, and grid operators typically dispatch generation resources in order of increasing cost. Resources with zero- or very-low-marginal cost (e.g., hydroelectric, wind, and solar) are generally dispatched first, followed by nuclear and combustion resources based on their fuel costs and efficiency. As load rises and falls over the day, the marginal cost of energy also rises and falls. Storage resources can charge when the marginal cost of energy is low and discharge when the marginal cost is high, displacing higher-cost generators and lowering overall system costs. This type of price-based operation is called energy arbitrage. Storage designed to conduct energy arbitrage generally has a duration of at least several hours, up to a day.

Electricity costs are generally low overnight, although in locations with large amounts of solar PV, the daytime solar peak can also result in very low-cost energy. The typical daily variation between high and low prices in most organized markets is relatively small, but "spikes" in prices can be lucrative for the resources able to deliver at those times.[11] While Colorado does not have a wholesale electricity market with a moment-to-moment clearing price of electricity, it still has lower-cost and higher-cost resources. Therefore, Colorado utilities can use storage to provide a form of energy arbitrage: They can arrange for storage to charge using energy from low-cost resources when the system load is low or when output

[10] There is a summary of capacity service and how U.S. wholesale capacity markets are designed at https://business.directenergy.com/understanding-energy/managing-energy-costs/deregulation-and-energy-pricing/capacity-markets.

[11] See, for example, "There's a Hidden Battery Play in the 'Extremes' of Power Prices" by B. Eckhouse at https://www.bloomberg.com/news/articles/2018-07-31/there-s-a-hidden-battery-play-in-the-extremes-of-power-prices.

from variable renewable resources is high relative to load, and discharge when the load net of renewable generation is high to reduce or avoid running the highest-cost resources.

Transmission and Distribution Infrastructure Deferral

Transmission and distribution lines are built to bring a certain capacity of energy from one point to another on the grid. When peak loads rise to the level that the wires are nearing their reliability limits, utilities make plans to invest in assets that will increase the capacity to meet future load. Evolving assessments of risk, spurred by events like forest fires, can also trigger utilities to plan for wires investments to maintain reliability. Actions that reduce the need for energy to flow during times of high demand or which increase local resilience or redundancy—such as energy efficiency, demand response, distributed generation, or energy storage located in the area with growing load—can help to avoid or defer a more expensive wires-based solution.[12] The duration of energy storage required to be a part of these "non-wires alternatives" (NWA) depends on the other resources deployed and the shape of the peak load. The required duration of such storage systems can extend to up to half a day if the systems are asked to meet more of the load.

2.2. Storage Technologies

Electric energy can be stored for later use by transforming it into different types of energy, such as physical motion, chemical potential, gravitational potential, or pressure. This section describes the technologies that use these transformations and their strengths and weaknesses with respect to providing the services described above.

Physical Motion: Flywheels

A flywheel stores energy by using electricity to spin the shaft of a motor which is attached to a heavy wheel that spins with very low friction. To extract energy, the spinning wheel is used to turn the shaft of the motor, which then acts as a generator. Roundtrip efficiencies can reach 90 to 95 percent. Flywheels can store and return energy very quickly and have relatively low capital cost per unit of power they can produce. However, storing large amounts of energy in a flywheel system is less cost-effective (since it generally involves needing to add flywheels). Flywheels also lose energy while it is stored, due to internal friction. As a result, flywheels are

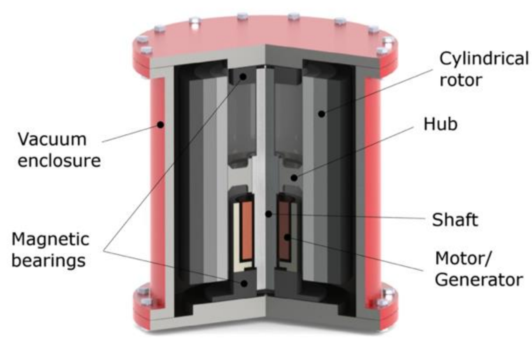

Figure 6. Flywheel schematic

Source: Wikimedia, licensed under CC Attribution-Share Alike 3.0.

[12] The Smart Electric Power Alliance report *Non-Wires Alternatives: Case Studies from Leading U.S. Projects*, available at https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/, summarizes the different resources that are being used as part of real-world NWAs.

best suited to low-duration applications like frequency regulation. Flywheel energy storage systems have a potentially long lifetime, since the components do not degrade.

The only large deployed flywheel systems in the United States are two 20 MW, 5 MWh (15-minute duration) systems deployed by Beacon Power in New York and Pennsylvania in 2011 and 2014, respectively.[13] These plants primarily provide frequency regulation service. Amber Kinetics is advertising a 4-hour flywheel system, but it has not completed any large deployments.[14]

Chemical Potential: Batteries

Batteries store electric energy by moving electrons from one chemical to another through a circuit, while keeping the chemicals separate. Electricity is restored by allowing the electrons to flow from one chemical back to the other through a wire. The two chemicals are called the anode and the cathode. There are numerous battery chemistries, but the primary distinction in form is between traditional rechargeable batteries and flow batteries.[15] Traditional batteries use solid anodes and cathodes, separated by an electrolyte (commonly a liquid, gas, or gel) through which electrons cannot pass. Each large battery system is composed of a number of smaller cells (e.g. the size of typical household batteries), each of which contributes to the overall performance of the system. Flow batteries use anolyte and catholyte[16] chemicals that are dissolved or suspended in a liquid, and flow past each other on opposite sides of a membrane to exchange ions and cause electrons to flow on the connected circuit. Grid-scale flow batteries are also composed of cells, but each cell can be much larger than in traditional batteries.

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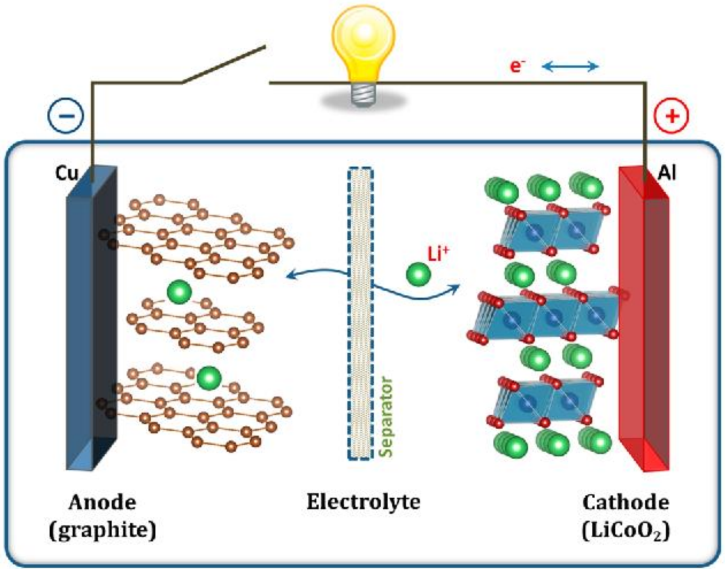
[13] Beacon Power, *20 MW Flywheel Energy Storage Plant*, available at https://www.sandia.gov/ess-ssl/docs/pr_conferences/2014/Thursday/Session7/02_Areseneaux_Jim_20MW_Flywheel_Energy_Storage_Plant_140918.pdf.

[14] Amber Kinetics, *Low-Cost Flywheel Energy Storage Demonstration*, June 2015, available at https://www.energy.ca.gov/2015publications/CEC-500-2015-089/CEC-500-2015-089.pdf.

[15] U.S. Energy Information Administration, U.S. Battery Storage Market Trends, May 2018. https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

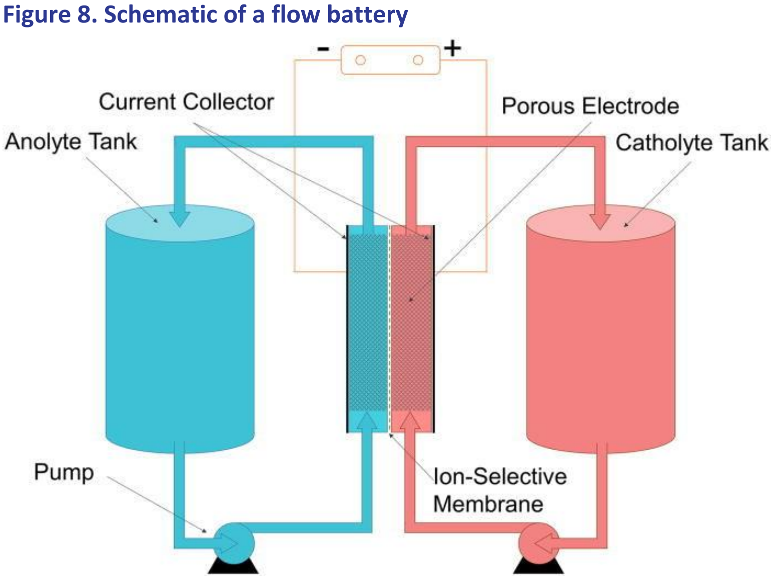
[16] An anolyte is a liquid that plays the role of the anode; a catholyte plays the role of the cathode.

Figure 7. Schematic of a lithium-ion battery



Source: Goodenough, J. B. and K. Park, "The Li-ion rechargeable battery: a perspective" Journal of the American Chemical Society, 2013. Accessed via https://www.semanticscholar.org/paper/The-Li-ion-rechargeable-battery%3A-a-perspective.-Goodenough-Park/42e965ce07774bc11bf7 b270b6249bda7c510fc9.

Figure 8. Schematic of a flow battery



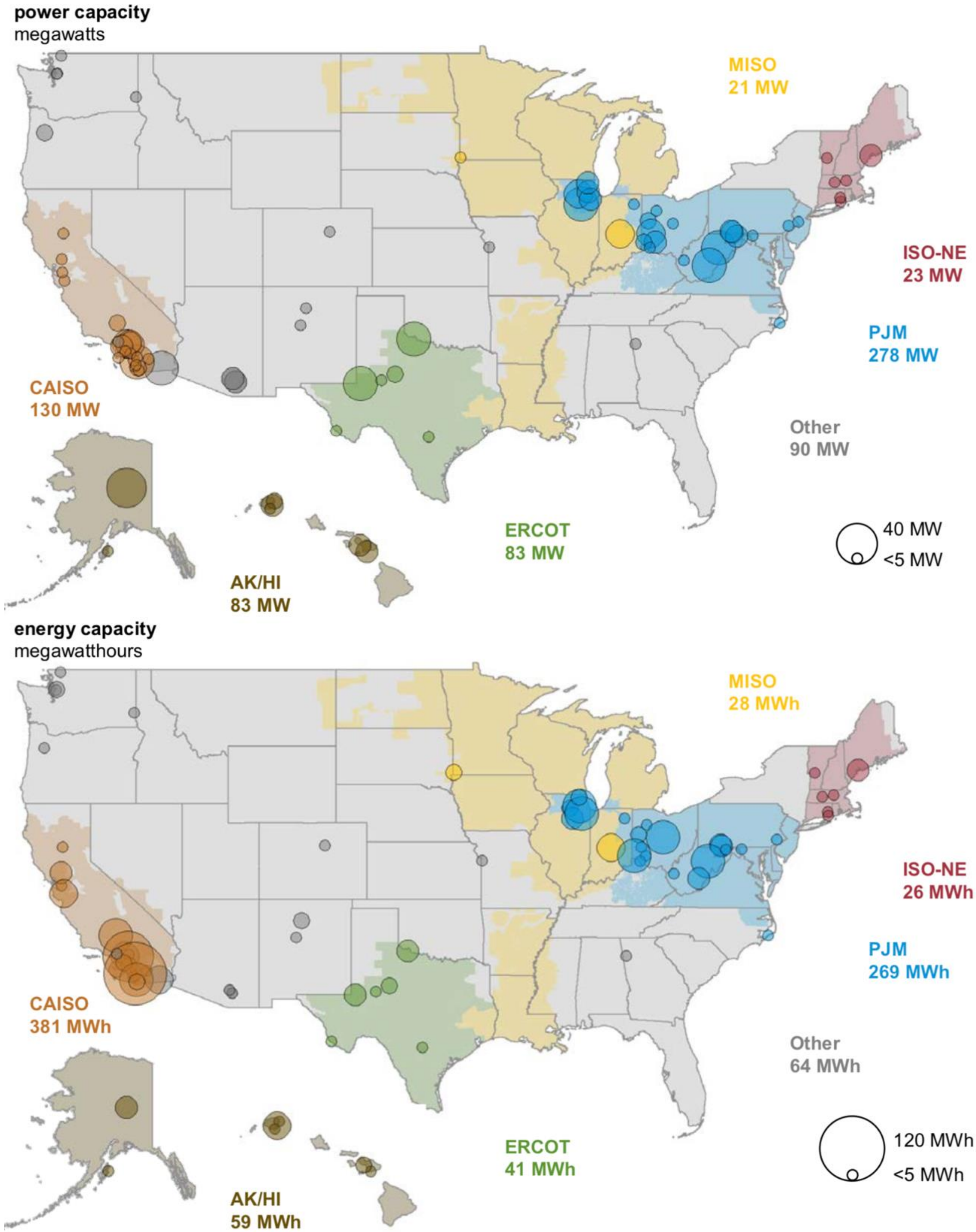
Source: Wikimedia, via https://en.wikipedia.org/wiki/Flow_battery.

Batteries represent the bulk of new energy storage technology deployed on the grid and have experienced rapid market growth within the last few years. Total installed capacity today is approximately 979 MW and 1,542 MWh in the United States.[17] Figure 9 shows the geographic distribution of large-scale batteries nationally as of 2017. Areas served by wholesale markets, where batteries can compete for revenue, dominate the deployment to date. There are three large-scale lithium-ion battery installations in Colorado (two of which are more recent than the EIA figure below): a 1 MW system owned by Xcel Energy and located at Panasonic's facility between Aurora and Denver International Airport; a 4 MW system owned by United Power, Inc. located off I-25 near Longmont, and a 4.25 MW, 8.5 MWh system at Fort Carson.[18]

[17] Data through 2017 from U.S. EIA Form 860; 2018 annual deployment from Energy Storage Monitor published by Wood Mackenzie and summarized at https://www.greentechmedia.com/articles/read/us-energy-storage-broke-records-in-2018-but-the-best-is-yet-to-come#gs.gikhxy.

[18] U.S. EIA Preliminary Monthly Electric Generator Inventory for March 2019. Accessed via https://www.eia.gov/electricity/data/eia860m/. "AECOM, Lockheed Martin Together Build Energy Storage System at Fort Carson" available at http://energystorage.org/news/esa-news/aecom-lockheed-martin-together-build-energy-storage-system-fort-carson.

Figure 9. U.S. large scale battery storage installations by region (2017)



Source: U.S. Energy Information Administration, U.S. Battery Storage Market Trends, May 2018. https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

Traditional Batteries

The most common battery chemistry for energy storage applications today is lithium-ion. Lithium-ion batteries are used for electronics and electric vehicles, as well as grid energy storage. There are numerous types of lithium-ion batteries, specialized for different applications. Global production of lithium-ion batteries in 2019 is expected to be approximately 160 GWh, up from 19 GWh in 2010.[19] Other types of rechargeable batteries used for grid applications include lead-acid (similar chemistry to traditional car batteries) and nickel-cadmium (NiCd). Lithium-ion has led the market because of its low weight (essential for electronics and automotive uses), its ability to maintain its capacity over many cycles of charging and discharging, its falling costs, and its increasing performance with technological and manufacturing improvements.

Traditional batteries come with a range of durations, typically ranging between half an hour and 10 hours. The duration can be selected based on the application and value proposition of the battery. Lithium-ion batteries are used today for all of the different services described above. The cost of low-duration batteries is primarily driven by the associated power electronics used to handle the output and input power, while the cost of longer-duration batteries is driven by the number of battery cells.

Flow Batteries

Flow batteries are an emerging technology with primarily grid applications. (They are too large for use in transportation or electronics.) They represent about 1 percent of battery capacity in the United States as of 2017.[20] Because the anolyte and catholyte materials can be stored in large tanks, flow batteries have the potential for very long durations and exhibit more reasonable cost scaling than traditional batteries as duration increases. They are also expected to have long operational lifetimes. They are best suited to provide long duration services such as energy arbitrage and non-wires alternatives. While flow batteries are generally not cost-competitive today, they are likely to find market support in applications where they are more cost-effective than lithium-ion due to the need for long durations.

Gravitational Potential: Pumped Hydroelectric

A pumped hydroelectric energy storage system stores electric energy by using it to pump water to an elevated reservoir. The system recovers the stored energy and generates electricity by allowing the water to flow back downhill through a generator. Open-loop pumped hydroelectric storage systems use a naturally occurring body of water, such as a river, as the source of water for the lower or upper reservoir. Once water has flowed back through the system, it flows away. Closed-loop systems operate separate from natural waterways and re-use the same water multiple times. Both open-loop and closed-loop systems lose some energy as it is stored due to evaporation; closed-loop systems must have water

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[19] Benchmark Minerals, "Who Is Winning the Global Lithium-Ion Battery Arms Race?" available at https://www.benchmarkminerals.com/who-is-winning-the-global-lithium-ion-battery-arms-race/.

[20] U.S. Energy Information Administration, U.S. Battery Storage Market Trends, May 2018. https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

added to make up for these losses. The round-trip efficiency of pumped hydro storage can exceed 80 percent.[21]

Pumped hydro storage is by far the most deployed form of electric energy storage in the United States and internationally. There are 18,440 MW of FERC-licensed pumped hydro capacity in the United States, of which 324 MW is the Cabin Creek Generating Station[22] near Georgetown, Colorado. The Cabin Creek station has a duration of four hours, and Xcel states that it uses the plant's rapid response capabilities for frequency regulation service and energy arbitrage. The Bureau of Reclamation's only pumped-storage facility, the Mt. Elbert Pumped-Storage Powerplant near Leadville, has 200 MW of generating capacity. The facility pumps water to a storage reservoir during off-peak times and releases it to meet peak demand and for system stability.[23]

Much of the nation's existing pumped hydroelectric storage resources were developed in the eastern United States to conduct energy arbitrage in the 1960s through 1980s. They were intended to allow relatively inflexible nuclear and coal generators to operate more efficiently by storing low-cost energy from nighttime hours to help meet the daytime peak. Limited site availability, substantial capital cost, and potential permitting risks resulting in long development times have slowed development, although there is some renewed interest. The Federal Energy Regulatory Commission (FERC) reports that it has issued three licenses for new systems since 2014, and there are pending applications for 2,666 MW of new capacity (none of it in Colorado, although there are 1,300 MW pending in Utah).[24]

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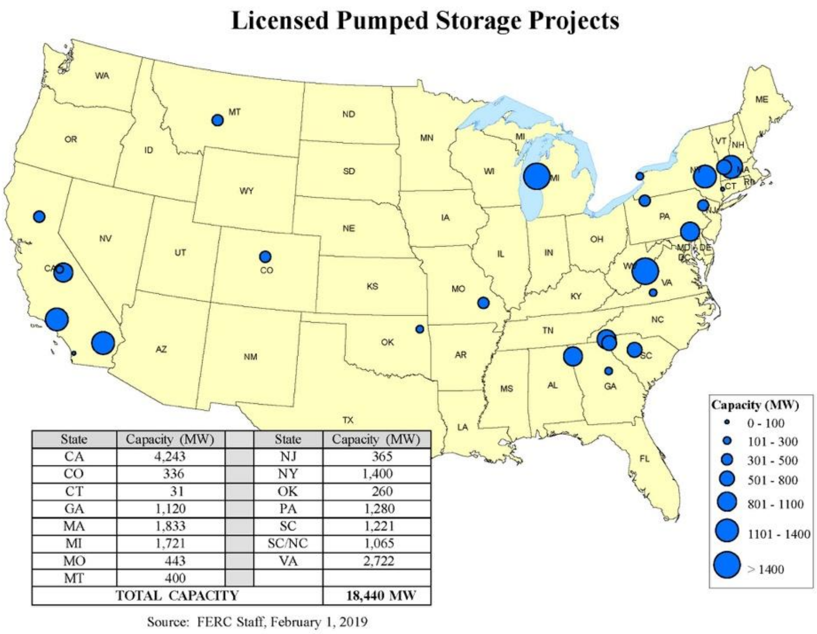
[21] Energy Storage Association, "Pumped Hydroelectric Storage" available at http://energystorage.org/energy-storage/technologies/pumped-hydroelectric-storage.

[22] Xcel Energy, "Cabin Creek Generating Station" available at https://www.xcelenergy.com/energy_portfolio/electricity/power_plants/cabin_creek.

[23] U.S. Bureau of Reclamation. *Mt. Elbert Pumped-Storage Powerplant; Fryingpan-Arkansas Project*, available at https://www.usbr.gov/projects/pdf.php?id=46.

[24] Federal Energy Regulatory Commission, "Pumped Storage Projects" and associated maps available at https://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp.

Figure 10. Map of licensed pumped hydro projects



State	Capacity (MW)	State	Capacity (MW)
CA	4,243	NJ	365
CO	336	NY	1,400
CT	31	OK	260
GA	1,120	PA	1,280
MA	1,833	SC	1,221
MI	1,721	SC/NC	1,065
MO	443	VA	2,722
MT	400		
TOTAL CAPACITY			18,440 MW

Source: FERC, https://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage/licensed-projects.pdf.

Pressure: Compressed Air Energy Storage

Compressed air energy storage (CAES) uses electricity to compress air. The air is stored under pressure until it is released through a turbine, regenerating electricity. Large-scale CAES systems rely on underground caverns to store the pressurized air, although small systems for distributed storage could use tanks. There are two large-scale CAES systems in the world: one 290 MW plant in Germany, and one 110 MW plant in Alabama. Both have been operational for decades. These plants primarily provide energy arbitrage service, pumping air into the cavern during off-peak hours and generating electricity during periods of higher demand.[25] There is one proposed CAES plant in the United States—a 324 MW facility in Bethel, Texas, that could store up to 16,000 MWh (an effective duration of almost 50 hours). The facility is scheduled to come online in 2022.[26] The project's proponents state that the Texas energy market is conducive to this resource because of the price and grid dynamics resulting from increasing wind energy penetration. Where appropriate geological formations exist and long-duration storage is required, CAES could compete favorably with batteries on a cost basis.[27]

[25] PowerSouth Energy Cooperative, "Compressed Air Energy Storage," available at http://www.powersouth.com/wp-content/uploads/2017/07/CAES-Brochure-FINAL.pdf.

[26] Apex CAES, "Bethel Energy Center" available at http://www.apexcaes.com/bethel-energy-center.

[27] St. John, J. "Texas to Host 217 MW of Compressed Air Energy Storage" Green Tech Media, July 9, 2013, available at https://www.greentechmedia.com/articles/read/texas-calls-for-317mw-of-compressed-air-energy-storage2#gs.7o05br.

CAES operators must add heat to the air as it expands to generate electricity. This heat typically comes from natural gas combustion, so existing large CAES systems produce some greenhouse gas emissions. If the expansion heat is supplied by heat stored from the compression step, the CAES system is referred to as "adiabatic," and fossil fuel combustion can be substantially reduced. There are no commercially operating adiabatic CAES systems. However, while traditional CAES systems have round-trip efficiencies of just 42 to 55 percent, proposed adiabatic designs could achieve efficiencies over 70 percent.[28]

Other Storage Technologies

There are other forms of energy storage, although they primarily serve to store electricity in another form, and then use that other form rather than re-generate electricity. For example, batteries in electric vehicles store electricity and can provide grid benefits by allowing controlled charging, but the energy is then used to drive the vehicles, rather than return it to the grid. There has been substantial research on vehicle-to-grid systems (referred to as "V2G"), where energy stored in vehicle batteries flows back onto the grid or serves load in the building where the vehicle is plugged in, but these systems have only been used in pilots thus far. V2G could provide substantial duration, subject to user limits on the discharge of their batteries before driving. V2G could be used for many of the energy services discussed above, provided that grid operators can count on the vehicles to be plugged in when the services are required.

Similarly, electricity can be used to make hydrogen by splitting water, and the hydrogen acts as an energy storage or carrier medium. Hydrogen can then be used as a thermal fuel or used to generate electricity using a stationary or vehicle fuel cell. Hydrogen production could produce storage of indefinite duration, provided the hydrogen can be stored. This might allow hydrogen storage technologies to be used for seasonal storage—shifting loads around the year to mitigate annual variation in loads (e.g. from heating) or resource availability (e.g. spring run-of-river hydroelectric production).

Electricity can also be used during off-peak hours to produce ice, which is then used for air conditioning or refrigeration during peak hours. This process effectively conducts energy arbitrage by shifting load from peak to off-peak times, without putting electricity back on the grid. Thermal storage can also be used in concentrating solar power plants to store the heat generated by the sun in the form of molten salt. That heat can then generate electricity when energy prices are higher and the sun is no longer shining brightly.

[28] Energy Storage Association, "Advanced Adiabatic Compressed Air Energy Storage (AA-CAES)" available at http://energystorage.org/advanced-adiabatic-compressed-air-energy-storage-aa-caes.

3. Storage Policies: Barriers, Incentives, and Best Practices

3.1. Federal Landscape

Federal regulations and wholesale markets

The FERC, which has regulatory authority over the interstate and bulk electric system, has worked over the last several years to develop a level playing field for energy storage technologies to participate in wholesale markets under its jurisdiction.

Storage provides a number of grid-supportive services, as discussed in Section 2.1. Many of these services are represented in wholesale markets, which have traditionally expected the services to be provided by energy generators rather than by energy storage. For example, frequency regulation service has been provided by flexible generators that can quickly ramp their output up or down. In FERC's Order 841, issued February 15, 2018, FERC established that storage resources must be allowed to compete in the markets where they can provide services. Specifically, FERC required "each RTO and ISO to revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets."[29] The operators of the nation's wholesale electricity markets have subsequently made compliance filings to adjust their tariffs to facilitate storage participation.

Colorado does not participate in any FERC-regulated wholesale market, so storage developments in Colorado cannot take advantage of FERC's Order 841. However, federal actions inform the context for Colorado and identify the types of barriers that the state might seek to alleviate. Wholesale markets provide a transparent process to identify the value that resources provide in terms of different capabilities, such as energy, capacity, and ancillary services. Outside of organized markets, state policymakers, regulators, and utility decision-makers lack this transparent value-discovery process. However, they can learn from wholesale market experiences elsewhere, including how storage demonstrates its value and the quantification of that value, which can inform their evaluation for in-state decisions.

Tax policy

Federal tax support for deployment of renewable energy resources, in the form of the investment tax credit (ITC) and production tax credit (PTC), has been a critical policy accelerating the deployment of renewable electric generation technologies, such as wind and solar PV. Standalone energy storage deployments are not eligible for any such tax credits. A PTC does not make sense for storage (since it

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[29] Federal Energy Regulatory Commission, Order 841, page 1. Available at https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf.

does not *produce* energy), but industry advocates have pressed Congress to expand the ITC to include standalone storage. Storage developers can take advantage of some or all of the ITC for deployments of solar PV plus storage, provided they meet appropriate conditions regarding the extent to which the storage is charged by the solar installation.[30] This can restrict how the storage is used to provide grid services. The ITC for solar is also set to decline from its current value of 30 percent starting in 2020, down to 10 percent in 2022 and beyond.

Outside the context of the ITC and PTC, storage is also eligible for accelerated depreciation for tax purposes when deployed without coupled renewable generation. Deployed with renewable generation that provides more than 75 percent of its charging, storage is eligible for an even faster (and thus more valuable) depreciation schedule.

3.2. Barriers

Lack of alignment between services, regulations, and ownership

The previous chapter describes the different grid-supportive services and sources of value that energy storage systems can provide. A major challenge for storage deployment is that the system owner needs to be able to monetize each of those potential value streams (or the subset that apply). However, that requires separate arrangements with the different entities to whom the services are being provided. Separation of utility functions of generation, transmission, and distribution into different entities is at the core of this complexity. Therefore, a vertically integrated utility has a greater likelihood of being able to realize and monetize the value that storage can provide at different levels of the grid. However, there is an inherent lack of transparency for non-utility developers and regulators in vertically integrated states, making access to information about storage value and pricing difficult or impossible. Prior to approving a storage investment, the regulator in a vertically integrated state needs access to utility information to be able to examine and critique each potential value to different parts of the utility's operations.

For example, a storage deployment that is primarily intended to defer or avoid a transmission investment would be providing value to the local transmission utility. At the same time, however, the same battery could provide both capacity and frequency regulation or other ancillary services to the local balancing authority, as well as voltage support to the distribution utility. BTM storage resources can be even more complex because they can provide the same services as wholesale systems but also can provide services like demand charge management or uninterruptible power to the hosting customer.

Each of the potential counterparties for a storage asset will demand specific services, deployed at particular times, and these requests could conflict. As a result, negotiating the terms for compensation

[30] National Renewable Energy Laboratory, *Federal Tax Incentives for Energy Storage Systems,* available at https://www.nrel.gov/docs/fy18osti/70384.pdf.

from each counterparty is complex and interdependent. Investors in a storage asset want assurance of access to revenue and a predictable revenue stream. In practice this means that successful non-utility storage systems typically depend on one or two more assured sources of revenue, and the systems' equity investors seek higher returns by finding ways to monetize other services.

In a wholesale market context, wholesale services such as energy arbitrage, capacity, and ancillary services are easily separated and monetized, with known rules and performance expectations. Market revenue alone may be sufficient to support some storage deployments. In other cases, additional revenue from services to a distribution-level customer or to a local distribution or transmission utility may be all that is required to make a storage asset an attractive investment.

Technology and market risk

The fastest-growing and most flexible energy storage technologies, such as lithium-ion batteries, are also relatively new technologies—especially when compared with the legacy generation and wires technologies that they compete with to provide some services. Batteries are less well developed even than relatively new generation technologies like solar PV or wind power, which have access to stable long-term power purchase agreements backed by their expected lifetime of production. Like wind and solar, the cost of storage assets is highly concentrated in upfront capital expense, so an investor in a storage project has a large portion of its expected lifetime investment at risk from the beginning. Institutionally conservative entities, like utilities and their regulators, are relatively risk averse. They do not want to be responsible in the event that a substantial investment fails to return value because it fails earlier than predicted, or the markets or services that were intended to provide revenue fail to deliver as much as expected. Risk translates to a higher demanded return, or a higher discount rate for future benefits, increasing the effective cost and raising a hurdle to deployment. Where storage is coupled with renewable generation, such as solar PV, the combined asset can be a more attractive investment than storage would be on its own. This is partly because of federal tax treatment lowering the cost of storage, and also because the relatively lower risk of the solar generation improves the risk-reward profile. Xcel Energy in Colorado has selected, via a competitive process supporting its Electric Resource Plan, three "solar plus storage" projects combining 560 MW of solar PV with 275 MW of battery storage.

Capital cost

While the cost of some kinds of energy storage systems, such as battery storage, has been falling and is expected to continue to decline, the substantial cost of energy storage is a barrier to deployment when combined with the other barriers discussed here. For example, the need to "stack" value from different revenue streams and to solve alignment problems between the beneficiaries of those services, would be less acute if storage systems were simply less expensive and could make a reasonable rate of return based on a smaller number of services provided. In fact, many storage installations have been justified primarily on the basis of single revenue streams, with some upside potential for investors contingent on the ability to find other revenue sources over the lifetime of the asset.

3.3. Policies and Incentives

States can take actions through legislation, regulatory requirements or practices, or executive leadership to establish supporting policies or lower barriers to storage deployment. This section describes different types of actions, identifies states that are leading in each type of action, and summarizes the current landscape in Colorado.

Targets and mandates

States can establish storage targets or mandates to provide market certainty and alleviate concerns about technology or market risk. We define a storage target to mean a published state policy objective to achieve a certain amount of new storage deployment, while a mandate is a requirement for regulated utilities to procure and deploy a certain amount. Mandates make more sense in vertically integrated contexts, where regulated utilities can capture the value that storage provides along multiple dimensions, and where the dominant paradigm is one of utility resource and grid planning. Targets, on the other hand, are a better fit in restructured states, where there are no central entities on which to place a mandate, and where the dominant paradigm is of competitive markets to provide services. Here, targets should be combined with other policies, such as incentives or market and business model reforms, to make the targets achievable by a diverse set of market participants.

A target or mandate gives storage developers the certainty that a market will exist for their products, and that it is worthwhile to invest in identifying potential projects and partners in the state. At the same time, risk-averse buyers, such as regulated utilities, will have greater confidence that their investments in storage will be deemed prudent and they will be able to recover their costs from ratepayers. Regulators know that they can approve storage investments with assurance that they are executing state policy established by the executive and/or legislative branches.

California set the bar for a state storage mandate in 2010 with the passage of Assembly Bill (AB) 2514. AB 2514 required the California Public Utilities Commission to set procurement levels for the state's investor-owned utilities. The CPUC subsequently set the IOU expectations to total 1,325 MW by 2020 and 1 percent of peak load for other load serving entities, split between transmission-level and distribution-level resources.[31] While described as a "target," this policy is a mandate under the definitions adopted in this report, in that the utilities are formally expected by their regulator to meet the procurement levels. The utilities are on track to meet these expectations, with Pacific Gas and Electric already well past its transmission-level storage target.[32] A subsequent act, AB 2868 in 2016, added an obligation to plan for (and invest in as appropriate) 500 MW of BTM storage.

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[31] California ISO, Relevant CPUC, Energy Commission, and ISO Proceedings & Initiatives: California Energy Storage Roadmap Companion Document available at https://www.caiso.com/Documents/CompanionDocument_CaliforniaEnergyStorageRoadmap.pdf.

[32] California Public Utilities Commission, "Energy Storage" available at https://www.cpuc.ca.gov/General.aspx?id=3462.

Other states have followed California's lead in setting storage mandates or targets. Table 1 summarizes the current policies as of early 2019.

Targets and mandates can play different roles, depending on the maturity of the energy storage market in the state. California set its mandate when the U.S. market was relatively immature, with the explicit goal of developing the market and establishing the state as a center for the industry. Colorado today is a developing market, with multiple MW-scale deployments and plans by Xcel Energy to develop 275 MW of storage with solar in the next few years. At the same time, the modeling presented later in this report shows that more than 1 GW of storage may be part of a least-cost portfolio for the state by 2030, and some of that storage will be deployed in the territories of the state's smaller utilities. If policymakers consider a target or mandate for Colorado, it should be designed to consider both the state's market and the unique utility contexts.

Table 1. Existing state storage mandates and targets

State	Target or Mandate?	Quantity
California	Mandate	1.325 GW by 2020 plus 500 MW of distributed
Massachusetts	Target	200 MWh by 2020, 1000 MWh by 2025
New Jersey	Target	600 MW by 2021; 2 GW by 2030
New York	Target	3 GW by 2030
Nevada	Mandate	Ongoing process at PUCN to set
Oregon	Mandate	At least 5 MWh by 2020 from each of two utilities

Planning

Utilities undertake numerous planning processes to inform their choices regarding investments in infrastructure and to describe their approach to the future of the electric grid. These planning processes relate to power supply and to the transmission and distribution (T&D) system. Regulatory oversight and rules regarding these plans are a key tool for policymakers to ensure that utilities are making choices about long-lived infrastructure that are consistent with a state's public policies. If a state wishes to ensure that energy storage is evaluated fairly, incorporating it into planning processes is a key step. Regulation of power supply planning is most relevant in states like Colorado that have vertically integrated utilities and have not adopted wholesale markets.

Power supply planning is generally the province of integrated resource planning (IRP). T&D planning has traditionally been the subject of less formal planning processes, although that is changing in some leading states such as New York and California. Storage can provide value to both the power supply and T&D utility functions, as discussed in the previous chapter. Thus, coordination of planning processes between these two spheres is important. Because storage may not currently be as cost-effective as alternatives that only provide power or T&D, looking at storage in terms of its net cost across all services can more accurately identify the least-cost path for ratepayers.

Integrated resource planning and resource approval processes

An IRP is a utility plan to meet the future need for energy, including peak demand, with an appropriate reserve margin.[33] IRPs consider both supply-side and demand-side resources, and they should consider storage (which sits at the boundary between supply and demand) as well. IRP analysis typically involves modeling of the utility's future power supply portfolio, integrated as necessary with needs for transmission to connect to resources. Models typically strive to minimize the required revenue requirement, subject to constraints set by reliability and public policy objectives, by selecting or retiring different assets or demand-side programs.

Consideration of storage in IRPs and resource approval processes can only be as good as the assumptions and modeling around cost and performance.[34] Most traditional electrical system planning models use hourly time resolution and can rely on example days or peak hours, rather than sequential modeling on complete days or weeks. Storage can deliver value on sub-hourly timescales (e.g. by delivering ancillary services and helping to integrate variable renewable sources, which also change output on a sub-hourly timescale) and need to be modeled sequentially so that the models can capture charging and discharging behavior. In addition, batteries have been steadily falling in price and increasing in performance, so a plan that looks forward a number of years and considers resources for deployment at some future date should evaluate the likely cost and performance of a storage technology at the time of deployment.

Storage evaluation in IRPs is relatively new. Colorado has joined a number of states in pursuing evaluation of energy storage in IRP proceedings. There has been more progress on this in western states, which have the combination of vertically integrated utilities and rapidly growing renewable generation resources, than in eastern areas with either wholesale markets or more reliance on traditional supply resources. Utilities and regulators in Washington and Oregon are demonstrating emerging best practices.

The Washington Utility and Transportation Commission (UTC) has adopted rules that require that storage be among the resources evaluated when any infrastructure decisions are made.[35] In particular, utilities risk that the regulators deem investments imprudent if storage was not considered. The risk of disallowance of cost recovery for imprudent investments serves as a strong motivator for utility behavior. The Washington UTC applies this rule to investments in T&D as well, which will serve to drive an integrated approach for storage across power supply and T&D planning.

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[33] For further background on IRP best practices, see *Best Practices in Utility Integrated Resource Planning*, prepared by Synapse Energy Economics for the Regulatory Assistance Project and available at https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf.

[34] See Energy Storage Association, *Advanced Energy Storage in Integrated Resource Planning (IRP): 2018 Update* for a further discussion. Available at http://energystorage.org/system/files/attachments/esa_irp_primer_2018_final.pdf.

[35] Washington UTC Docket U-161024, Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition, 11 Oct 2017, available via https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=161024.

In Oregon, Portland General Electric's (PGE) 2016 IRP reflected the state's energy storage mandate to acquire at least 5 MWh of storage by 2020.[36] Storage targets or mandates work well with a planning-based approach to storage policy, because through this approach the IRP process can help identify the most promising ways to integrate storage to meet the state's target or mandate. PGE used the 2016 IRP to develop a framework for storage evaluation that it could use for future evaluation. Such frameworks include a "net cost" approach to comparing storage with other types of resources, as well as other approaches to quantifying and stacking both operational and capacity value of storage. While the IRP did not identify a specific storage investment for the action plan, PGE has subsequently procured storage coupled with a wind generation facility.[37]

Colorado's House Bill 18-1270, the Energy Storage Procurement Act, has started a process in Colorado to define how utility Electric Resource Planning (ERP; the Colorado version of IRP) must account for energy storage. The Act directed the Public Utilities Commission to establish mechanisms for the utilities to use in evaluating energy storage in their planning processes, and for utility storage procurement and data transparency. The resulting PUC rules[38] require consideration of energy storage, including documentation of the methodology and assumptions used to evaluate energy storage, "including, but not limited to: integration of intermittent resources; improvement of reliability; reduction in the need for increased generation facilities to meet periods of peak demand; and avoidance, reduction, or deferral of investments." Utilities are also required to propose how energy storage systems smaller than 30 MW can be acquired in all-source competitive procurements. As of this writing, Colorado is also revising its overall Electric Resource Planning rules in proceeding number 19R-0096E.

Transmission and distribution planning

Utility planning practices for T&D systems are less standardized across the country than IRP practices. Distribution system investments and practices have traditionally been subject to less regulatory oversight than transmission or generation, simply because the investments in individual distribution assets are substantially smaller in comparison. However, distribution systems in aggregate represent a large fraction of utility assets, and the increasing use of distributed energy resources (DERs), such as distributed solar PV generation, has resulted in greater attention to how these systems are planned and operated.

Two states that have taken leading approaches to distribution system planning are New York and California. The New York Public Service Commission (NY PSC) required the development of Distributed System Implementation Plans (DSIPs) as part of its Reforming the Energy Vision proceeding. DSIPs reflect New York's policy objective of moving to a more distributed energy system, with the utility acting as a

[36] Portland General Electric, "Integrated Resource Plan" available at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf.

[37] Portland General Electric, "Wheatridge Renewable Energy Facility" available at https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/wheatridge-renewable-energy-facility.

[38] Colorado PUC, 723-3 Electric Rules, accessible via https://www.colorado.gov/pacific/dora/electricrules/.

“distributed system platform” intended to animate markets for distribution-level services. DSIPs are intended to provide more information transparency about the distribution system and opportunities for distributed resources, including energy storage, to contribute to the energy system. By focusing on services, rather than technologies, the New York approach has been relatively agnostic regarding energy storage, although the NY PSC did require each utility to deploy two storage projects.[39]

California’s “Distribution Resources Plan” (DRP) process was instigated by passage of Assembly Bill 327 in 2013. It required each regulated utility to submit a DRP in 2015 to “identify optimal locations for the deployment of distributed resources,” including energy storage.[40] The DRP process drove the state’s utilities to model and analyze each of their circuits and identify the hosting capacity of their distribution systems for distributed generation resources like solar PV, and also to identify locations where DERs have the potential to lower costs on the grid. Utilities also developed pilots for distribution investment deferral using DERs, including evaluation of energy storage as part of the resulting portfolios.[41]

Storage deployments to address transmission or distribution challenges need to be located in specific places and offer durations of at least several hours. This makes batteries, which can be scaled and sited flexibly, the technology of choice. However, most battery energy storage deployments in the United States have been relatively small—there are only 22 operating installations in the country with a capacity over 15 MW, and none over 40 MW.[42] Transmission systems are generally shaped by larger resources—on the scale of generators of 100 MW or larger. As a result, there have been relatively few opportunities for storage installations to play into bulk transmission planning. Storage can more readily contribute near the interface of T&D systems, where the relevant scales are smaller. One example that could have parallels in Colorado is the case of Boothbay, Maine.[43] In Boothbay, GridSolar operated a combined set of resources, including solar PV, local generators, efficiency, demand response, and energy storage (500 kW, six-hour duration), which was less expensive than building a second transmission line to serve the community. In actuality, the projected load growth did not materialize, and the pilot successfully avoided the construction of an unnecessary transmission line. Colorado communities considering additional transmission lines to serve increasing load, or increased resilience in

[39] New York Public Utilities Commission, Cases 14-M-0101 and 16-M-0411, order of March 9, 2017 on “Distributed System Implementation Plan Filings,” available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={35E255DD-92FF-420B-8363-895892992103}.

[40] California Public Utilities Commission, proceeding R.14-08-013. https://www.cpuc.ca.gov/general.aspx?id=5071.

[41] See, for example, Pacific Gas and Electric “PG&E’s Distribution Resources Plan Webinar” available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5140.

[42] U.S. EIA Preliminary Monthly Electric Generator Inventory, March 2019, accessed at https://www.eia.gov/electricity/data/eia860m/.

[43] N. Lanyi for Smart Electric Power Alliance, “Waiting for load growth: Maine’s Boothbay project shows how non-wires alternatives head off expensive grid upgrades”, available at https://sepapower.org/knowledge/waiting-for-load-growth-maines-boothbay-project-shows-how-non-wires-alternatives-head-off-expensive-grid-upgrades/.

the face of fire risk, could consider storage coupled with other distributed energy resources located within their communities.

The Colorado PUC has updated its regulations[44] in response to the passage of the Energy Storage Procurement Act to require that utilities "include consideration of energy storage systems in its planning processes as an alternative to construction or extension of distribution facilities where appropriate." For transmission, utilities must describe alternatives considered for any transmission investment, "including consideration for energy storage systems."

Utility and state incentive programs

Utilities that can recover the costs of their storage investments in electric rates generally do not need any other form of financial incentive to invest in utility-owned storage once it is selected in their planning processes, as discussed above. However, third-party developers and investors, as well as customers hosting BTM storage, may require some form of financial incentive to deploy storage. These incentives would address the "lack of alignment" barrier by compensating the storage owner for services the asset can provide but which are not readily monetized.

Incentives can take numerous forms, including upfront incentives or rebates, ongoing payments, or tax credits. New York has launched incentives programs totaling $280 million to support achieving the state's 3 GW storage target. These programs have been directed at both utility-scale and BTM deployments. New York is using a "block" structure for its incentives in which projects developed earlier (in time or in aggregate capacity, depending on the program) receive larger per-unit incentives. Massachusetts has coupled storage deployment with solar PV in its "Solar Massachusetts Renewable Target" (SMART) program and compensates the solar project owner with an increased payment per kWh generated by the solar facility. The per-kWh amount depends on the relative size of the solar and storage facilities and the duration of the battery system. Maryland has adopted a tax credit approach, offering a 30 percent tax credit for storage investments (thus matching the Federal ITC for solar PV).

Interconnection

The electric grid must be able to accommodate the loads and injections that it experiences without sacrificing reliability or power quality. Interconnection rules govern how new loads and generators are evaluated in context before they can be attached to the grid. States typically have different rules and cost allocation approaches for interconnecting load and generators. Energy storage challenges this paradigm by acting as both a load and a generator. Some storage systems may have a large nameplate capacity but be designed entirely to manage load or demand charges for the hosting customer, and they will never export to the grid at all. Storage is also potentially much more controllable than typical loads (and some generators) and is likely to be operated in a way that assists, rather than hampers, grid operations. For example, economic operation of a storage system would likely result in the system

[44] Colorado PUC, 723-3 Electric Rules, accessible via https://www.colorado.gov/pacific/dora/electricrules/.

acting as a load during otherwise low-load times, since the cost to charge the storage at those times is low, and as a generator during high-load times, since the value of energy delivered at those times is high.

Numerous states, including Colorado, have updated aspects of their interconnection rules or procedures to address energy storage. Updates across the country have followed the FERC's 2013 update to its Small Generator Interconnection Procedures to add energy storage as a specified and covered technology. These updates have also been driven by increased experience with storage interconnection as battery storage deployment increases. Interconnection rules identify the kinds of studies that are required for different types of resources. More extensive studies are more expensive, so requiring more extensive studies than are strictly necessary can have a chilling effect on deployment. States re-visiting their rules for storage have addressed which types of studies are required for different types of storage installations. For example, a storage installation that never exports to the grid could be simple to interconnect even if an equivalent system installed in a different configuration and for a different purpose would require extensive study.[45] However, one challenge for interconnection approvals of storage is that the dispatch strategy of a storage resource may change over its lifetime.

Colorado has an open proceeding, 19R-0096E, that addresses interconnection rules, among many other topics. In addition, utility-specific processes have established operational and interconnection guidance and procedures specific to energy storage, particularly regarding treatment of systems that do not export to the grid.[46]

Novel business models and ownership structures

One way to address the "lack of alignment" barrier is to have multiple parties involved in owning and/or operating a storage asset, with each one seeing value in different areas. For example, a utility could contract for one aspect of a storage asset's operation, but ownership remains with a third party who can then monetize other services in other ways. Alternatively, a utility could own the asset but seek diverse sources of revenue to recover the costs, rather than only recovering the full cost through rates. To date, neither of these approaches has extended past the pilot- or small-program stage in any jurisdiction. Utilities and policymakers can learn from experiences and practices developed in pilots and programs across the country.

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[45] See a summary of numerous state actions in Z. Peterson, National Renewable Energy Laboratory, "Emerging Practices for Energy Storage Interconnection" November 2018 at https://www.nrel.gov/dgic/interconnection-insights-2018-11.html.

[46] Xcel Energy "Guidance No. 1 for the Interconnection of Electric Storage as Stand-Alone Sources, Parallel Operation for Customers without Generation, and in Parallel with Self-Generation" at https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Residential/CO-solar-residence-Storage-Guidance-1.pdf and "Non-Unanimous Comprehensive Settlement Agreement" in Proceedings 16AL-0048E, 16A-0055E, and 16A-0139E, regarding the Public Service Company of Colorado, at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=854366.

One example of the model of utility ownership with compensation outside of base rates is Green Mountain Power (GMP) in Vermont. To manage regional costs for transmission and capacity, GMP is deploying Tesla Powerwall battery systems as a pilot in customers' homes and retaining control over charging and discharging during high load periods. Customers pay $30/month for two 5 kW, 13.5 kWh batteries, which together can power the home for up to 24 hours.[47] Customers experience uninterruptible power and avoid the use of a generator, at a much lower cost than full ownership of the batteries. GMP is also offering a "bring your own device" program in which customers with their own storage systems can receive an upfront payment of $850 to $1000 per kW of capacity to make their systems available for utility dispatch for 10 years.[48] Rocky Mountain Power in Utah has proposed a similar, but more geographically concentrated program: the utility proposes to partner with a property developer building a multi-family development to install utility-owned battery storage in each of the 600 units, to be charged by on-site solar and available for the utility to use for capacity service (demand response).[49]

Non-wires alternatives (NWAs) provide a promising opportunity for third-party storage ownership with a utility contract for specified services. NWAs are collections of distributed resources that together allow a utility to avoid or defer a grid upgrade at the transmission or distribution level. Storage can contribute to NWAs, as discussed in the previous chapter. A utility could pursue an NWA through a set of contracts with third-party suppliers, as Consolidated Edison has done in New York's Brooklyn-Queens Demand Management program. A storage asset that contributes to an NWA would need to be available during times when the local load needs to be managed, but could provide other services during other times, such as regulation service or uninterruptible power to the hosting customer.

3.4. Recommendations for Colorado

Based on the review of policies and practices summarized above, we recommend that Colorado policymakers consider the following actions:

- Establish a procurement mandate for energy storage resources. The level should be commensurate with the amount of storage needed to cost-effectively operate the grid as it transitions toward increasingly renewable and low-carbon resources. Potentially differentiate based on the size or the roles (generation, transmission, and/or distribution) of the utility.
- Learn from ERP evaluations of storage to spread emerging best practices and valuation approaches for services storage can provide to all of Colorado's utilities. Increase

[47] Green Mountain Power, "Resilient Home" available at https://greenmountainpower.com/product/powerwall/

[48] Green Mountain Power, "Bring Your Own Device" available at https://greenmountainpower.com/bring-your-own-device/

[49] Rocky Mountain Power, *Application to Implement Programs Authorized by the Sustainable Transportation and Energy Act*, filed in Utah PSC Docket No. 16-035-36, March 8, 2019. Available at https://pscdocs.utah.gov/electric/16docs/1603536/306971AplImplProgAuthSTEP3-8-2019.pdf

transparency for the value of services and the cost of storage, for example by using competitive procurement processes.

- Establish a process to identify and screen for opportunities for NWAs (including energy storage and other DERs) to meet load growth and reliability objectives. Evaluate these projects on a net cost basis, accounting for costs and benefits accruing to diverse parties.
- Support innovation in storage ownership business models.
- Continue to revise interconnection and planning processes to incorporate lessons learned from storage procurement and deployment.

4. MODELING THE FUTURE OF STORAGE IN COLORADO

To develop the above recommendations in this report, Synapse engaged in a rigorous modeling exercise to evaluate the future role and benefits of energy storage under different policy scenarios in Colorado between 2019 and 2029. We modeled energy storage at both the grid scale as well as BTM.[50] The policy scenarios we modeled represent different strategies that the State of Colorado may undertake in the near term. Each scenario results in different levels of storage penetration and renewable deployment across the state. The results of the grid-scale analysis focused on the changes to energy resource capacity and generation, whereas the results of the BTM storage analysis focused on the net benefits provided by BTM storage in a pilot program context. Finally, we evaluated the economic impacts (employment, income, and GDP) of the policy scenarios at the grid-level in Colorado.

4.1. Scenarios Modeled

Synapse modeled a Reference Case, a Carbon Price Case, and two policy scenarios. For the policy scenarios, we modeled variables that will impact the rates of adoption of storage within the state relative to the Carbon Price scenario. The four scenarios are:

- **Reference Case:** Though Colorado did pass the Sunset Bill in the spring of 2019, this scenario represents a future without it and the associated resource-planning carbon price. This scenario is included to illustrate the impact of the Sunset Bill on Colorado's energy future.
- **Carbon Price Case:** This scenario is a base case representing the current trajectory of Colorado's energy future. This Case includes the resource-planning carbon price that was recently passed in the Sunset Bill (SB 19-236). Note that this is not a traditional

[50] Grid-scale energy storage is connected to the transmission system, whereas BTM energy storage is connected to the distribution system (though in a BTM configuration).

carbon price and therefore does not impact the Colorado economy. The carbon price only impacts the economics of resource planning for utilities by adding a price per short ton of carbon dioxide on carbon-emitting resources (e.g., coal, natural gas, oil). The price starts at $46/short ton in 2020 and escalates by 2 percent per year for the remainder of the study period.[51] This carbon price drives a significant level of renewable investment relative to the level of renewables installed in the state today.[52] Unlike the Reference Case, this scenario does not include any "must-runs" for coal units, meaning that there is no minimum capacity factor for coal units in this scenario.

The Carbon Price Case assumes that the Colorado Renewable Energy Standard (RES) will not be expanded and that existing RES requirements will remain in place. The Colorado RES has two tranches: one for IOUs (with a distributed generation carve-out), and one for municipal or cooperative utilities. The RES requirement stays flat at the 2020 level of 30 percent of IOU sales and 10 percent of municipal/cooperative utility sales.

At present, the majority of Colorado cooperatives have signed long-term contracts with Tri-State Generation and Transmission Association (Tri-State G&T) that restrict each cooperative from generating more than 5 percent of its total energy consumption from its own generating units. This scenario assumes that the "self-generation" from each cooperative will remain flat at 5 percent of its total consumption, with the remaining generation purchased from Tri-State G&T through the study period. For modeling purposes, Synapse assumes that each cooperative self-generates 4 percent of its total consumption in 2018[53] and will reach the 5-percent self-generation limit of its total consumption in 2019 and for the remainder of the study period.

Synapse relied on EIA form 860 for data on plant retirements in the state of Colorado, and Xcel Energy's "Preferred ERP" option outlined in its 2016 ERP 120-Day Report filed on June 6, 2018 for data on plant additions.

- **Coop Scenario (Increase in Self Generation of Cooperatives):** In the Coop Scenario, the amount of self-generation utilized by the coops in 2018 and 2019 is the same as in the Carbon Price Case. Beyond 2020, Synapse assumes that the self-generation limit enforced by the contract with Tri-State G&T would be relaxed by 1 percent each year, resulting in a self-generation limit of 15 percent by 2029. The model assumes that any self-generation by the coops will be met with solar PV, energy storage, or paired

[51] Colorado Senate Bill 19-236: https://leg.colorado.gov/sites/default/files/documents/2019A/bills/2019a_236_enr.pdf.

[52] The state of Colorado has passed a resource-planning carbon price, which is included in the Carbon Price Case and both policy scenarios (Coop and RES Scenarios). However, the carbon price represents a significant departure from the current state of renewable development in the state and therefore places the state on a path that deviates significantly from the Reference Case.

[53] https://www.cleancooperative.com/uncooperative.html.

resources. As with the Carbon Price Case, the remaining generation will be purchased from Tri-State G&T. The carbon price also holds true in this scenario.

- **RES Scenario (Expanded RES):** In the RES Scenario, Synapse assumes that Colorado's RES requirements increase after 2020. For IOUs, the RES will require that 75 percent of total electricity sales come from RES-eligible technologies by 2029. Similarly, for municipalities and cooperatives, the RES requirement will increase to 30 percent of total sales by 2029. The carbon price also holds true in this scenario.

  Although energy storage is not currently an eligible technology to meet the Colorado RES, this scenario assumes that regulations are amended and generation from paired storage resources can meet the RES requirement.

4.2. Grid-Level Modeling

To assess the impact that increased storage penetration will have on the future electric grid in Colorado, Synapse used the EnCompass model developed by Anchor Power Solutions and the accompanying National Database created by Horizons Energy. EnCompass is a single, fully integrated power system platform that performs both production-cost and capacity-expansion modeling.[54] We include details of the modeling setup and input assumptions in the appendix. The grid-level modeling focused on battery technologies (as opposed to other forms of energy storage discussed in Section 2). Synapse modeled both standalone batteries and those paired with solar PV.

First, we present the result of the Carbon Price Case and two policy scenarios. Afterward, we present the Reference Case compared to the Carbon Price Case, to illustrate the impact of the Sunset Bill.

Carbon Price Case Results

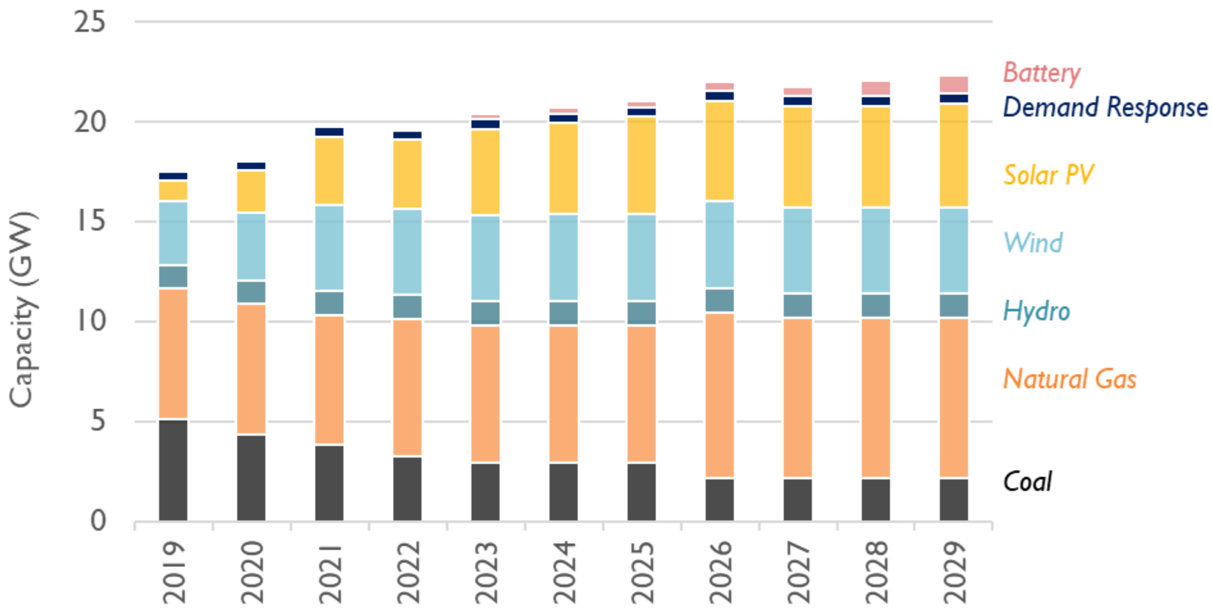
In the Carbon Price Case, installed capacity of both renewables and batteries increases substantially throughout the study period between 2019 and 2029 (Figure 11). Installed capacity of battery storage increases from 0 GW in 2019 to nearly 1 GW in 2029. Over the same period, installed solar PV (utility-scale and distributed) capacity increases by 4.1 GW and wind capacity by 1.1 GW. This renewable buildout is driven partially by the resource-planning carbon price included in the Carbon Price Case. The increased buildout of batteries takes place particularly in the later years, due to the falling cost of lithium-ion batteries and zinc flow batteries. By 2029, 6 percent of the batteries built in this scenario are paired with solar PV, and the remainder are standalone batteries.

As shown in Figure 12, net energy generation in the Carbon Price Case increases 14 percent from about 67 GWh in 2019 to 76 GWh in 2029 to meet increasing demand in Colorado. All resources except coal increase their contributions to total generation over the study period. By 2029, Colorado's energy

[54] For more information on EnCompass, see https://anchor-power.com/encompass-power-planning-software/.

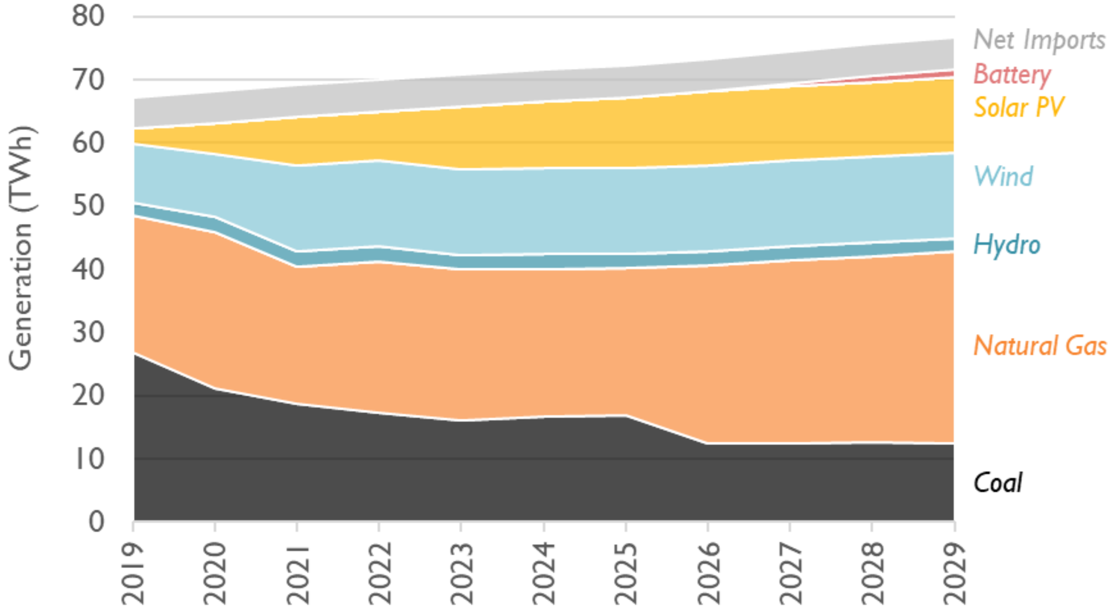
generation is met primarily by natural gas (40 percent), wind (18 percent), solar (15 percent), and coal (16 percent). The remaining 11 percent comes from hydro, battery storage, and imports. Energy discharge from battery storage represents 2 percent of total generation in the Carbon Price Case by 2029. In terms of net additional generation from 2019 to 2019, battery storage represents 6 percent of new generation in the state.

Figure 11 . Carbon Price Case total installed capacity in Colorado by resource from 2019–2029



Source: Synapse calculations based on EnCompass outputs.

Figure 12. Carbon Price Case energy generation in Colorado by resource from 2019-2029



Source: Synapse calculations based on EnCompass outputs.

Coop Scenario Results

The Coop Scenario results are very similar to the Carbon Price Case results, in terms of both renewable resource and battery capacity and generation.

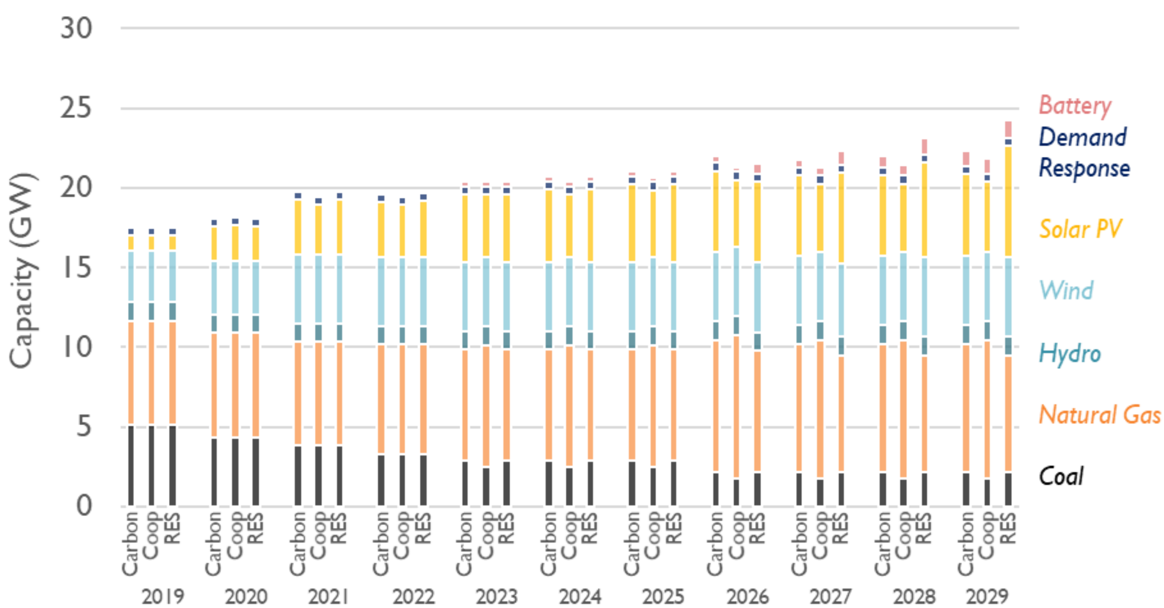
The similarity between the Coop Scenario and Carbon Price Case results mainly from two factors. First, in the Carbon Price Case, the state is already building out a substantial amount of emission-free resources (6.3 GW)—relative to the state's current trajectory—due to the resource-planning carbon price that comes into effect in 2020. Second, the increase in coop self-generated storage and solar is very minor relative to the Carbon Price Case—1 percent per year. Given that Colorado's annual cooperative load represents a relatively small portion of the state's total load (28 percent), a 1 percent annual increase in cooperative self-generation could only lead to a maximum theoretical annual increase in Colorado's battery or solar generation of 0.3 percent.

Despite this theoretical maximum, the Coop Scenario builds slightly less total capacity than the Carbon Price Case for all resources except natural gas. In this scenario we assume that were would be a decrease in generation from a Tri-State G&T-owned coal plant to reflect the increase in coop self-generation. However, resource economics favors filling the gap with natural gas combined cycle capacity—likely to fill a firm capacity need in the most cost-effective manner—rather than solar and battery storage. Filling the gap with natural gas also reduces solar and battery capacity slightly because combined cycle units are built in much larger capacity increments than utility-scale solar PV—700 MW versus 20 MW—thus reducing the capacity need for smaller capacity solar installations. Regardless, by

2029, the difference in capacity builds between the Coop Scenario and the Carbon Price Case is minor—500 MW, or 2 percent of the total Carbon Price Case capacity. Table 2 provides an overview of the difference in capacity builds relative to the Carbon Price Case in each year of the model. By 2029, 12 percent of the batteries built in this scenario are paired with solar PV, and the remainder are standalone batteries.

Table 3 shows the differences in electricity generation over the study period relative to the Carbon Price Case. In 2021, the generation mix is very similar between the Coop Scenario and the Carbon Price Case. By 2025, generation from solar PV and coal has decreased, while generation from natural gas has increased. This trend continues out to 2029. The increase in natural gas generation and decrease in solar PV generation is due to the pattern described above—a combination of resource economics and differences in capacity addition increments. The difference in generation from batteries between the Coop Scenario and the Carbon Price Case is negligible compared to the differences in generation from the other resource types.

Figure 13. Capacity builds (GW) by resource type and scenario in years 2019 to 2029



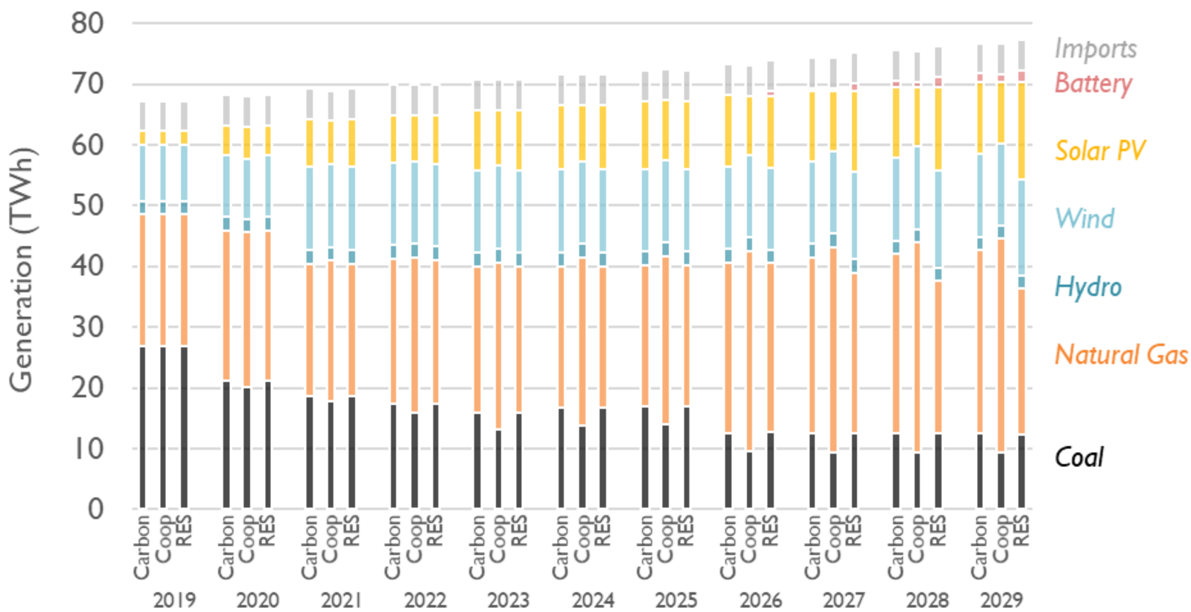
Source: Synapse calculations based on EnCompass outputs.

Table 2. Difference in installed capacity (MW) relative to the Carbon Price Case in 2021, 2025, and 2029

Resource	Coop Scenario			RES Scenario		
	2021	2025	2029	2021	2025	2029
Solar	-300	-640	-760	0	16	1,800
Wind	0	0	0	0	0	600
Battery	0	16	-16	0	-4	190
Natural Gas	0	700	700	0	0	-700
Coal	0	-430	-430	0	0	0

Source: Synapse calculations based on EnCompass outputs.

Figure 14. Generation by resource type and scenario in years 2019 to 2029



Source: Synapse calculations based on EnCompass outputs.

Table 3. Difference in generation (GWh) relative to the Carbon Price Case in 2021, 2025, and 2029

Resource	Coop Scenario			RES Scenario		
	2021	2025	2029	2021	2025	2029
Solar	-700	-1,900	-1,750	0	40	4,300
Hydro	-150	50	-5	0	2	50
Battery	0	20	-150	0	-10	480
Natural Gas	1,500	4,500	4,800	0	-30	-6,300
Coal	-900	-3,020	-3,100	0	-10	-140

Source: Synapse calculations based on EnCompass outputs.

RES Scenario Results

In the RES scenario, more renewable energy capacity is built out compared to the Carbon Price Case from 2026 onward. By 2029, there is an additional 1,800 MW of solar PV capacity, 600 MW of wind capacity, and 190 MW of battery capacity in the RES Scenario (Figure 13 and Table 2). This is expected, as the expanded RES requires IOUs to supply 75 percent of their generation with renewable resources by 2029. By 2029, 9 percent of the batteries built in this scenario are paired with solar PV, and the remainder are standalone batteries.

Table 3 shows the differences in electricity generation over the study period relative to the Carbon Price Case. As with the Coop Scenario, through 2025, the generation mix is very similar between the RES Scenario and the Carbon Price Case. By 2029, generation from both coal and natural gas has dropped compared to the Carbon Price Case, and generation from solar, batteries, and hydro has increased. In 2029, the RES scenario is expected to generate 480 GWh of battery discharge above what is expected in the Carbon Price Case.

We can partially explain the late build-out and generation of renewables by the carbon price embedded in the Carbon Price Case. The carbon price drives a build-out of renewables in the Carbon Price Case to a level which exceeds the RES in the near term. However, by the later years of the model, the RES requirements exceed the capacity of renewables incented purely by the carbon price. The late build-out and discharge of battery resources, on the other hand, is due to declining technology costs causing battery storage to become cost-competitive with other renewable resources toward the end of the study period.

Reference Case Results

The Reference Case does not include the Sunset Bill's resource-planning carbon price. Therefore, the Reference Case has more coal capacity (Figure 15) and coal generation (Figure 16) than the Carbon Price Case in nearly every year of the study period. This is not only because carbon-emitting resources are less economically favorable in the resource planning process, but also because the Carbon Price Case does not retain any minimum capacity factor requirements for coal units ("must-runs"). In 2029, the Carbon Price Case has 300 MW less coal capacity than the Reference Case and generates 5,000 GWh less energy from coal compared to the Reference Case.

Figure 15. Annual installed capacity by resource type for Reference and Carbon Price Case, 2019–2029

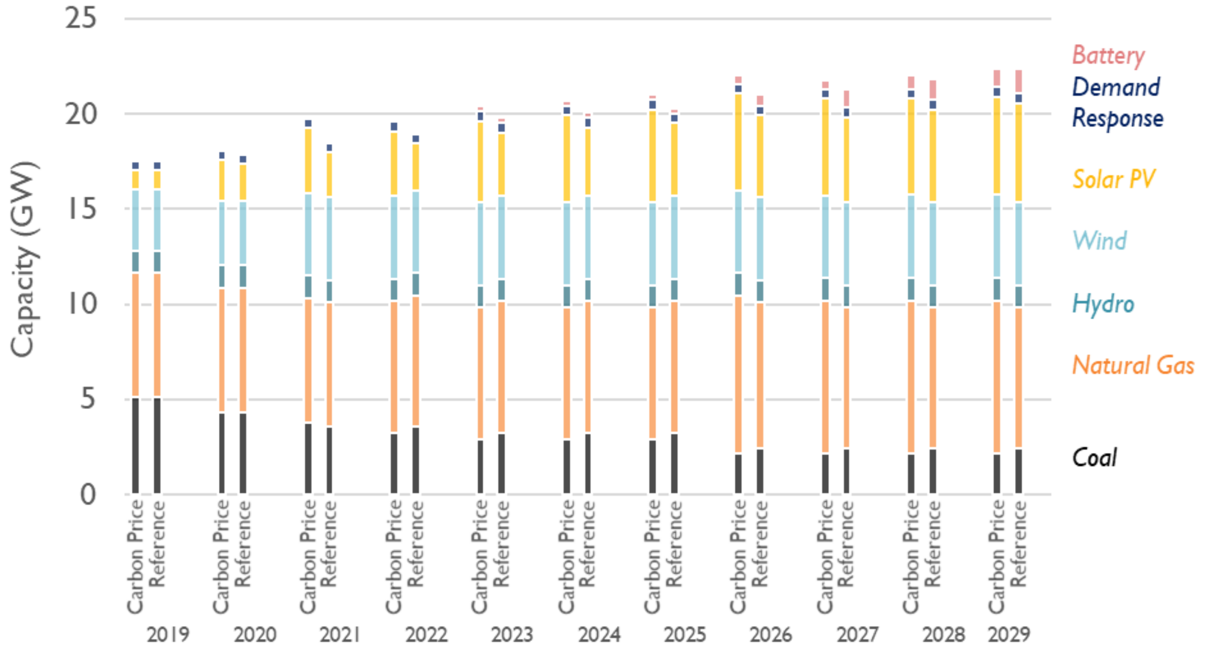
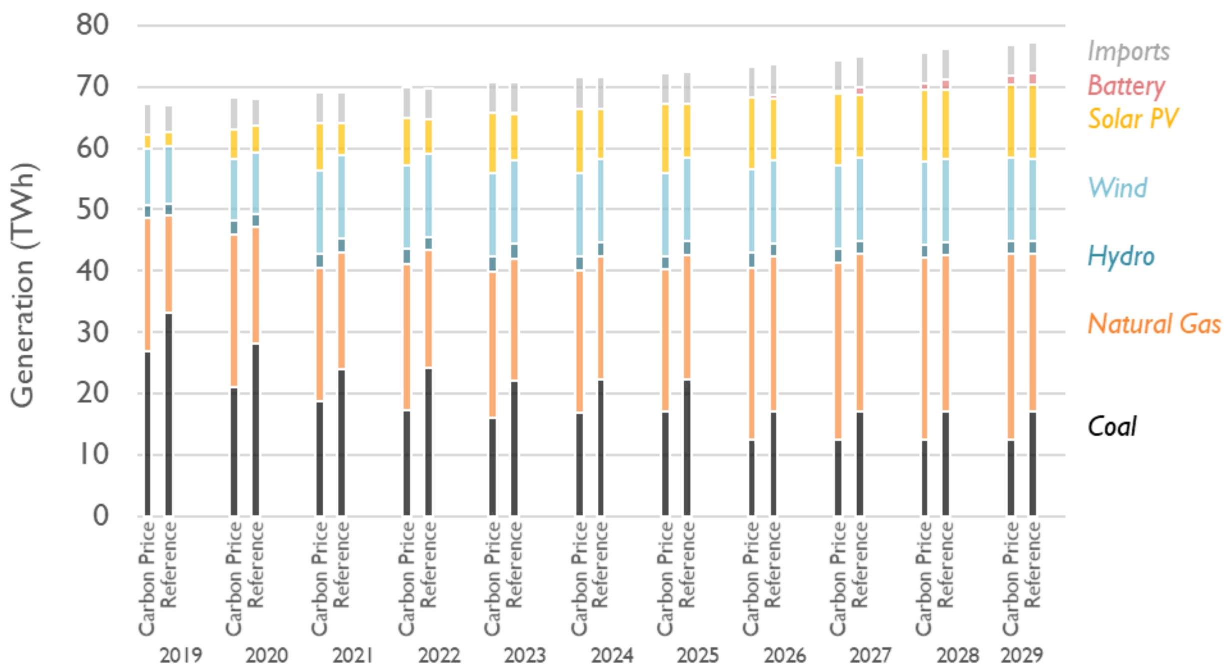


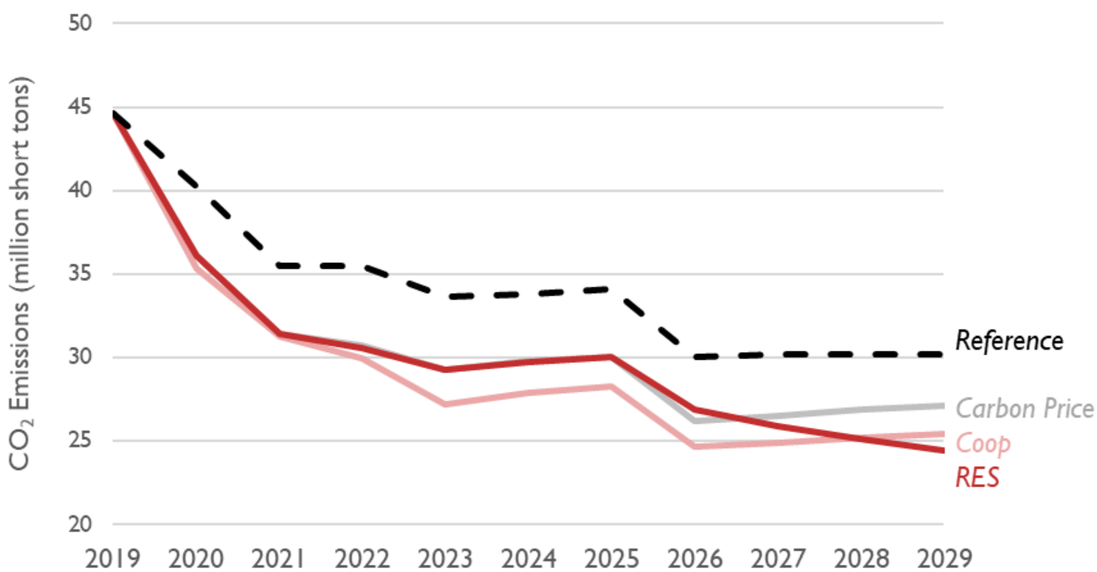
Figure 16. Annual generation by resource type for Reference and Carbon Price Case, 2019–2029



In all four scenarios, the modeling projects a decrease in annual carbon dioxide emissions from the electric sector throughout the study period. Over the course of 2019, all scenarios are expected to emit nearly 45 million short tons of carbon dioxide (**Error! Not a valid bookmark self-reference.**). By 2029, the RES Scenario is projected to have the lowest annual emissions at 24 million short tons per year—a reduction of 46 percent over 10 years. In 2029, the Coop Scenario is projected to have 25 short tons of carbon dioxide emissions per year and the Carbon Price Case will have 27 short tons of emissions per year.

Though the difference between the Reference Case and the Carbon Price Case is only 3 million short tons of carbon dioxide in 2029, the Sunset Bill is estimated to be responsible for a *cumulative* reduction of 40 million short tons of carbon dioxide from 2019 through 2029.

Figure 17. Annual carbon dioxide emissions by scenario, 2019–2029



Note: The y-axis starts at 20 million short tons of carbon dioxide, rather than zero million short tons, to highlight the differences between scenarios.

Discussion

In Colorado's current trajectory (Carbon Price Case), battery storage is projected to represent 12 percent of the state's new capacity and 6 percent of the state's new generation over the next decade. This increase includes Xcel Energy's commitment to building 275 MW of batteries in Colorado in the near term. If Colorado expands its RES, battery capacity and generation will exceed that of the Carbon Price Case, though only marginally, resulting in a total of 1.1 GW of capacity and 1.9 GWh of generation in 2029. For comparison, as of 2019 the United States had just under 1 GW of installed battery capacity. In other words, over the next decade under the RES Scenario, Colorado will exceed the current battery capacity installed nationally. Even so, batteries are expected to generate only 2 percent of Colorado's total annual generation by 2029. The RES expansion is therefore recommended to help drive additional development of energy storage in the state. In contrast, the Coop Scenario is not projected to increase storage capacity in the state, primarily because the impact on capacity and generation in Colorado is so slight.

As discussed above, the limited build-out of batteries before the late years of the study period is due to our assumptions that battery storage has relatively high capital and operating costs relative to other traditional generators in the absence of storage-friendly policies and mandates to enable the deployment of storage in the state. If Colorado established a transparent, stable revenue stream to value the non-traditional services provided by energy storage (e.g., frequency/voltage support, reserves, peak load support—see Section 2.1), storage would be able to compete earlier with more traditional resources and enable Colorado to steer away from large, carbon-intensive traditional energy resources. Supporting energy storage in this way will help the state meet its renewable energy goals while maintaining a cost-effective and efficient electricity grid.

4.3. Behind-the-Meter Storage Modeling

Synapse developed a custom spreadsheet model to evaluate the costs and benefits of BTM storage technologies offered to residential customers in Colorado.[55] While customers have multiple storage technology options, our analysis focused on a generic 5 kW/13.5 kWh BTM storage product with a 10-year lifetime. We used the parameters of Xcel Energy's Residential Battery Demand Response Program as our default model inputs.[56] Xcel Energy designed this program to help integrate renewables onto the grid, specifically when wind generation is low.

In the first year of the program, Xcel expects 250 residential participants, each of whom will receive $535 towards the purchase of a single-battery storage system. The utility expects an additional 250 participants in the second year of the pilot. Though Xcel's program does not consider the use of a two-battery system in the residential pilot program, we also modeled a two-battery alternate pilot to compare the incremental costs and benefits of two batteries per customer instead of one.[57] The two-battery alternate is also assumed to include a double incentive payment of $1,070.

Synapse used the same electric system modeling scenarios for the BTM analysis with a Carbon Price Case and two policy scenarios. Between the Carbon Price Case and the two policy scenarios, the number of participants does not change. This allows the model to accurately reflect the difference in benefits due only to the policy change and its impacts on energy prices. We used the energy prices from the EnCompass modeling results.

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[55] System costs consist of the costs of the battery, supporting hardware, installation, and annual operations and maintenance (O&M). System benefits are made up of several components, including avoided T&D costs. Synapse researched utility-specific T&D avoided costs in Colorado and applied these to the number of battery installations expected in Xcel's service territory. Also included in the benefits component of the analysis are the impacts on capacity additions and energy prices, which are derived from the EnCompass results. Avoided energy and capacity costs are calculated by applying those inputs to the energy and capacity savings, as calculated by the spreadsheet model.

[56] Xcel Energy. (2019). 2019/2020 Demand-Side Management Plan: Electric and Natural Gas. https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/DSM-Plan.pdf.

[57] Other U.S. utilities conducting residential battery pilot programs (e.g., Green Mountain Power, Liberty Utilities) are administering a two-battery program for their customers.

Synapse's modeling based dispatch of battery storage resources on peak load, with batteries cycling once per day, charging at night between 2 am and 5 am, and discharging in the afternoon between 4 pm and 7 pm. Batteries can charge directly from the electric grid; it is not necessary for a customer to have installed solar PV. The model estimates energy savings attributable to the storage projects during peak and off-peak periods, as well as total annual energy, capacity, transmission, and distribution savings. We provide additional model details and assumptions in the appendix.

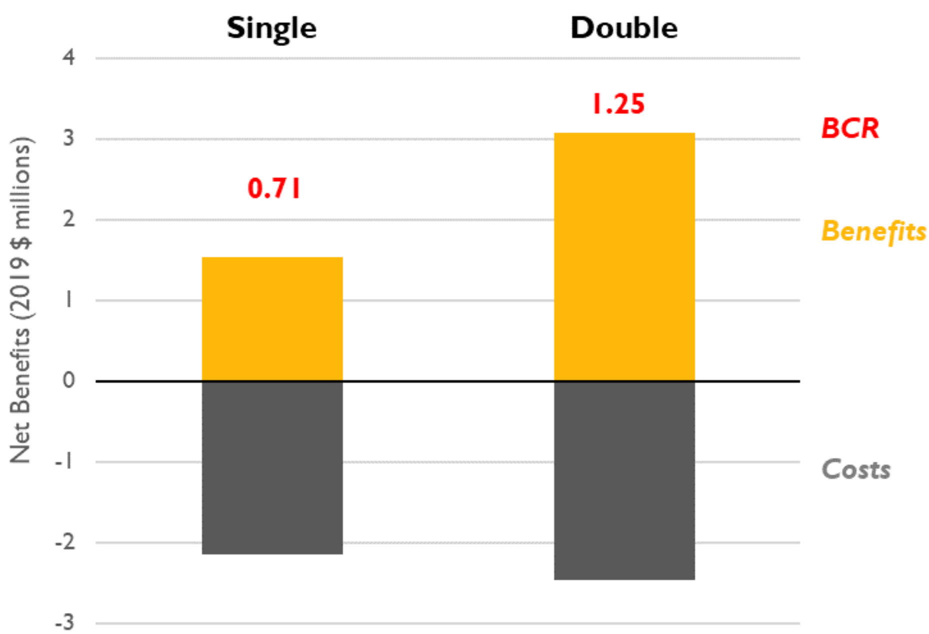
Results are shown below in terms of total benefits, costs, and the benefit-cost ratio (BCR). A BCR above 1.0 implies that the program is cost-effective, or that the total lifetime benefits outweigh the total lifetime costs. The opposite is true of a BCR that is below 1.0.

Results

In the Carbon Price Case, the cumulative lifetime benefits of a single-battery system do not outweigh the total program operating costs; the cumulative 10-year BCR is 0.71 and the net cost of the program of $0.62 million (2019 $). When an additional battery is added to the customer's system, incentive costs go up but only marginally compared to the increased capacity savings. The double-battery participants have a BCR of 1.25 and a cumulative net benefit of $0.61 million (Figure 18). The cumulative total benefits for the double-battery system is about $3 million compared to $1.5 million for a single-battery.

Theoretically, benefits could also increase by doubling the number of program participants. However, there are two reasons this may not necessarily be the case. First, there are some benefits associated with reduced fixed costs (e.g., installation costs, inverters) by concentrating two batteries in a single system. And second, many of the fixed program costs borne by Xcel Energy (e.g., marketing and administrative costs) would remain static if the existing customers gain a second battery, but those costs may increase if the number of total program participants increases.

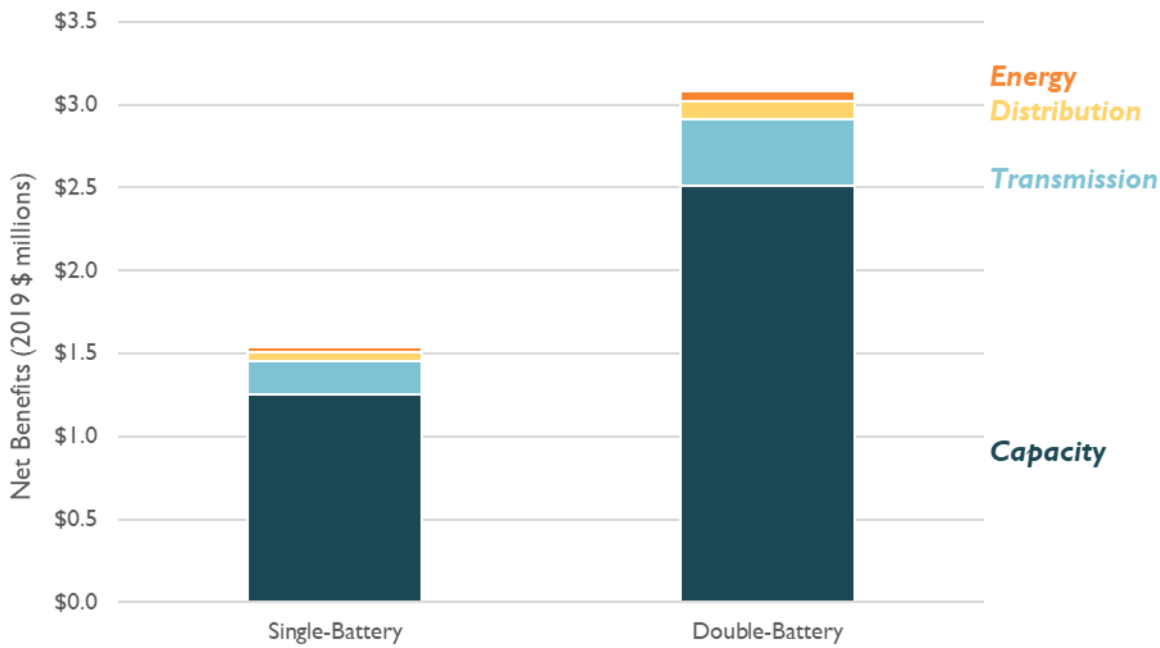
Figure 18. Benefits, costs, and BCR of a single- vs double-battery system



Source: Synapse calculations.

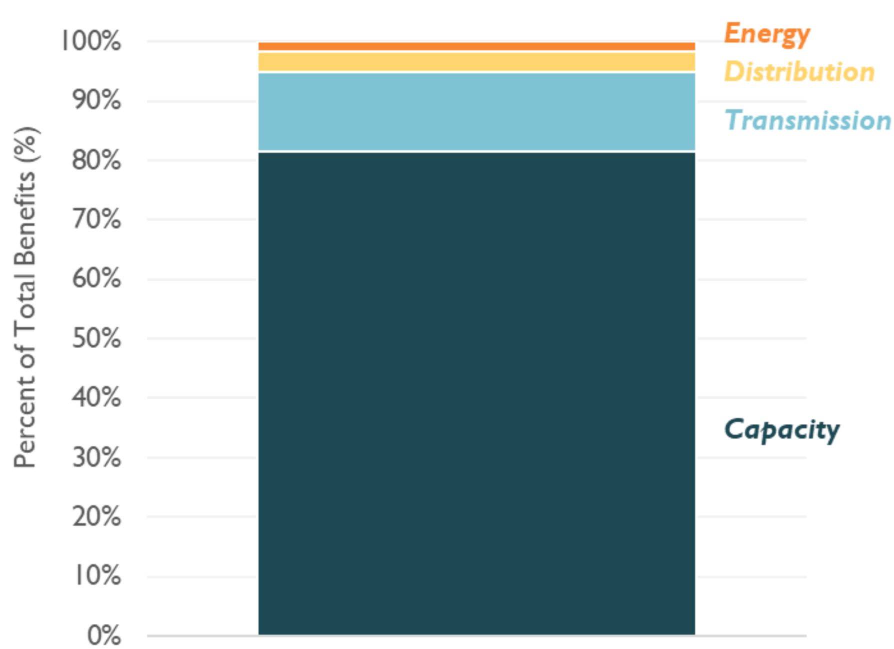
Energy prices (derived from the EnCompass results) are relatively consistent across the Carbon Price Case, Coop, and RES Scenarios, therefore net benefits are also similar. This similarity is because avoided energy costs represent a small percentage of total savings compared to avoided capacity costs. Capacity savings account for around 80 percent of total savings, whereas energy savings account for only 0.1 percent of total savings (Figure 19 and Figure 20). It is also worth noting that battery cycling increases overall energy consumption by about 90 kWh per battery unit annually during off-peak hours. This increase is due to round trip efficiency losses of the battery. In other words, the system must consume 1.1 kWh in order to discharge 1 kWh of energy.

Figure 19. Total benefits by value stream for a single- and double-battery system



Source: Synapse calculations.

Figure 20. Percent of total avoided costs for single- or double-battery system



Source: Synapse calculations.

Discussion

The Xcel Residential Battery Demand Response Program assumes a single battery per customer and provides an incentive for a single battery. However, our 10-year lifetime analysis indicates that the program would only be beneficial to the electric system and the utility if the residential customer utilizes two (or more) batteries. A participant supplying a single battery would not be able to provide enough capacity to cover the utility's program costs and incentives. Therefore, a minimum of two batteries should be a requirement for program participation. The results of this study are encouraging because the benefits are not dependent on any future policy, as the battery program is cost-effective in all scenarios.

Despite achieving a positive benefit to the utility, participant benefits are harder to measure and were not included in our study. Given the current incentive amount, it is difficult to know whether participant benefits outweigh costs of the system. While the incentive amount is only a small portion of the total upfront cost of the battery system, the combination of the incentive and increased resiliency should ideally encourage program participation. A further analysis of participant benefits could be modeled in a future study.

4.4. Economic Impacts

Synapse applied the results from the grid modeling exercise—together with insights and first-hand research from storage expert interviews—as inputs for an economic and employment impact analysis.

Synapse began this task by identifying the leading companies located in Colorado that participate in the value chain of energy storage. First, we interviewed experts at the Energy Storage Association (ESA), CleanTech Colorado, Colorado Solar and Storage Association (COSSA), and Western Resources Advocates (WRA). Conversations with these organizations led to additional conversations with companies participating in the storage supply chain in Colorado, including Able Grid Energy Solutions and Fluence. Insights from these interviews contributed to the development of our modeling approach to quantifying the benefits of energy storage to Colorado's economy.

Synapse used the IMPLAN model to assess the economic impacts of our selected policy scenarios with varying levels of storage penetration.[58] Inputs to this analysis include modeling results from EnCompass as well as custom spending patterns for different energy resource types, as developed by Synapse based on data from the National Renewable Energy Laboratory's JEDI model and Synapse's own research. Our analysis accounts for the following types of economic impacts:

1) **Direct impacts**: These include changes in employment, GDP, and income associated with shifts in production in directly affected industries. For example, these might include increased employment

[58] IMPLAN is an industry-standard input/output model that we used to determine impacts on several critical aspects of Colorado's economy, including household income level, statewide gross domestic product (GDP), and employment.

associated with the engineering, construction, and manufacturing of energy storage projects in Colorado.

2) **Indirect impacts**: These include impacts throughout the supply chains of directly affected industries. For example, these might include changes in production at steel manufacturing facilities that serve power plants.
3) **Induced impacts**: These include impacts associated with re-spending of employee wages and consumer energy savings in the wider economy. For example, these might include increased employment at grocery stores that serve employees of a new renewable energy facility.

Storage Landscape Interview Results

Synapse conducted interviews with supply chain experts to gather information about how much money stays in Colorado when a battery is purchased in the state. To understand this supply chain process, we asked several experts about battery manufacturing in Colorado, cost components of batteries, battery installation costs, and supply chain wages. The discussions below are focused on lithium-ion (Li-ion) batteries, as they are currently the most prevalent and cost-competitive technology for energy storage.

CleanTech Colorado

Currently, there are no companies in Colorado that manufacture Li-ion batteries. However, there are several companies that produce and supply individual components to the major manufacturers (e.g., Panasonic, LG, Samsung, Hitachi, Tesla). CleanTech Colorado believes that Colorado may be a good place in the future to host flow battery manufacturing.

According to CleanTech Colorado, about 70 percent of a battery's cost is the materials and the cathode accounts for around half of those materials costs. Colorado is home to two companies that treat cathodes for battery life extension. Colorado is also home to several inverter companies.

Able Grid Energy Solutions

Able Grid was able to provide the most detailed estimates of the cost components that comprise a typical energy storage project in Colorado. According to Able Grid, approximately 10 percent of a battery storage development project budget goes toward development interconnection, most of which is labor cost. Another 10 percent goes toward legal fees, other fees, and profit. The remaining 80 percent goes toward materials, including the batteries themselves (about 40 percent of project costs), inverters and other electronics (about 20 percent), and steel and other construction materials (about 20 percent). Most of these materials are imported from elsewhere, and none of the experts we spoke with considered it likely that a substantial Colorado industry would arise to manufacture these materials. However, the costs associated with project development, installation, and permitting drive local economic benefits.

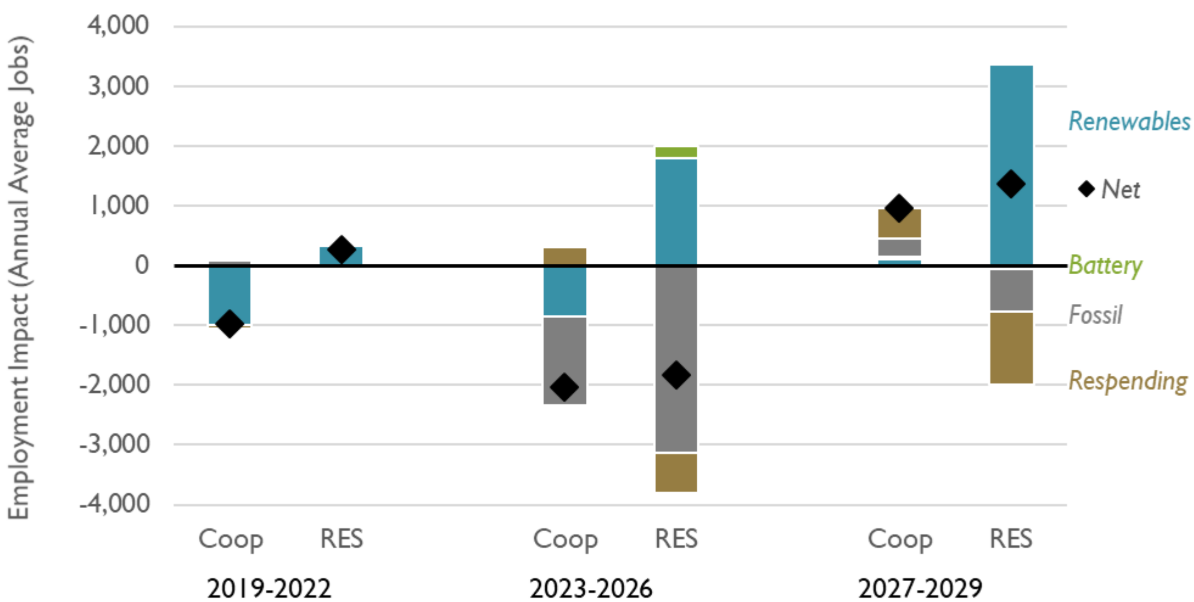
Fluence

Fluence is one of the largest global integrators of battery storage projects, providing engineering, procurement, and construction (EPC) services for battery storage installation as well as operations and maintenance (O&M) services over the lifetime of storage projects. Fluence echoed the sentiment that manufacturing of batteries and related power electronics is unlikely to take place in Colorado, as these industries are already well-developed in other places. However, Fluence noted that local economic benefits can arise in Colorado from the installation and operations of batteries. Fluence distinguished between two forms of battery O&M cost: (1) preventive and reactive maintenance, which primarily consists of labor costs; and (2) augmentation, which primarily consists of capital costs associated with replacing storage system components. According to Fluence, there is currently a wide range in the proportion of battery storage O&M costs associated with preventive maintenance versus augmentation.

Employment Impacts

Figure 21 displays the average annual Colorado employment impacts of the Coop Scenario and RES Scenario relative to the Carbon Price Case in each of three periods covering the study timeframe. The results indicate small net employment impacts under both alternative scenarios. Under the RES scenario, positive impacts associated with increased investment in renewables and batteries outweigh negative impacts associated with reduced spending on fossil fuel-fired generating facilities and reduced disposable income available to spend on non-energy goods and services. Under the Coop Scenario, negative effects associated with reduced spending on renewables, fossil fuel plants, and batteries offset positive effects associated with consumer energy savings. Over the full study period, employment impacts amount to a net average annual increase of approximately 1,000 jobs under the RES Scenario and a decrease of 440 jobs under the Coop Scenario. The benefits of the RES Scenario relative to both the Coop Scenario and Carbon Price Case are largely driven by increased investment in solar and wind between 2026 and 2029.

Figure 21. Average annual employment impacts of Coop and RES Scenarios relative to Carbon Price Case

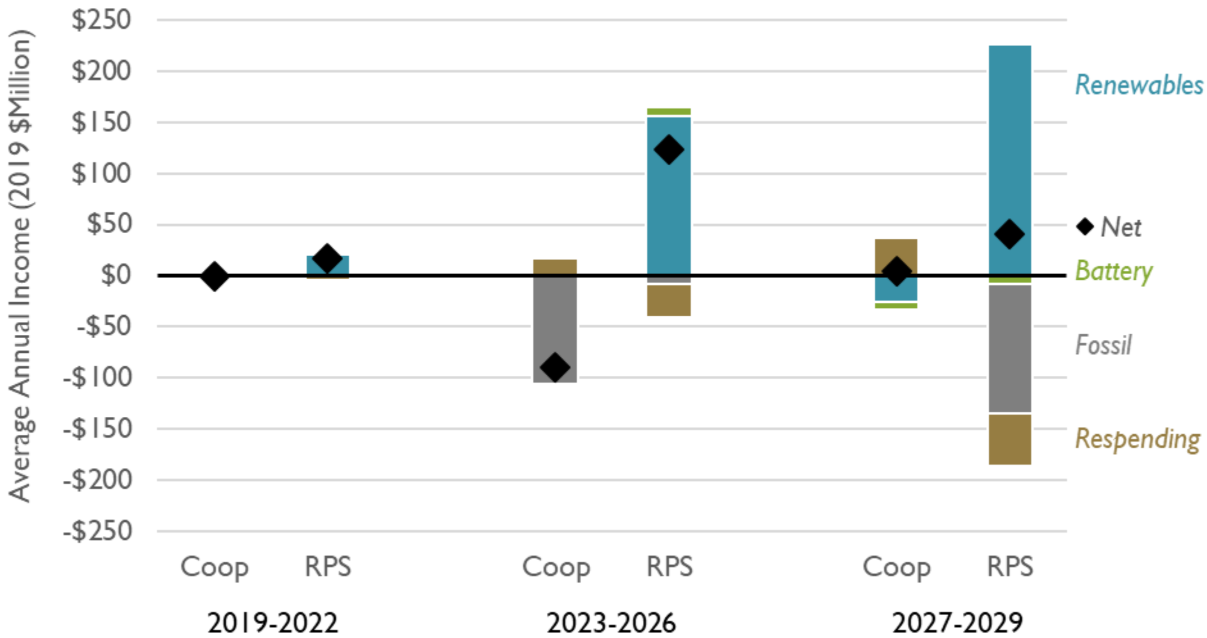


Source: Synapse calculations.

Income Impacts

Figure 22 presents our findings regarding income impacts in Colorado. Income impacts are the net change in disposable income of any person impacted by the storage industry in Colorado. We again find small positive net impacts under the RES Scenario and small negative net impacts under the Coop Scenario. Over the full study period, we find net average annual income impacts of about $60 million under the RES Scenario and -$30 million under the Coop Scenario.

Figure 22. Average annual income impacts of Coop and RES Scenarios relative to Carbon Price Case

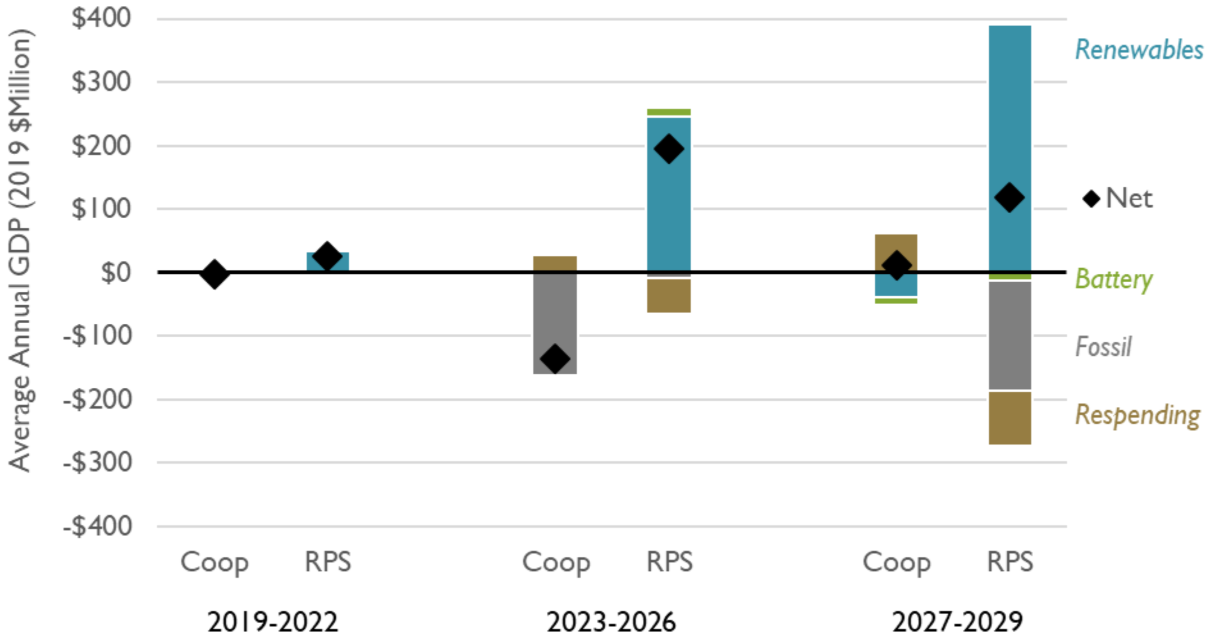


Source: Synapse calculations.

GDP Impacts

Figure 23 displays our net GDP impact results. We again find small positive net impacts under the RES Scenario and small negative net impacts under the Coop Scenario. Over the full study period, we calculate net average annual GDP impacts of approximately $110 million under the RES Scenario and -$50 million under the Coop Scenario.

Figure 23. Average annual GDP impacts of Coop and RES scenarios relative to Carbon Price Case



Source: Synapse calculations.

Discussion

Relative to the Carbon Price Case, the Coop Scenario has minimal negative economic impacts—primarily because there is slightly less capacity added to the state than the Carbon Price Case in each year. The RES Scenario, however, yields a modest increase in positive economic impacts relative to the Carbon Price Case, due to the increase in renewable and battery capacity builds in the state.

For every $2 million spent on battery construction and operation, we estimate that about three new jobs are sustained for a given year.[59] For context, Xcel Energy's planned addition of 275 MW in battery storage is likely to create over 550 jobs for construction and nearly two jobs in every year afterward for maintenance.[60] As utilities and developers in Colorado invest in energy storage in the future, the state will continue to see net positive impacts from the addition of storage.

[59] We calculate that 2.2 job-years are created from $1 million spent on battery construction and 0.6 job-years are created from $1 million spent on battery operation and maintenance. Note that one job-year is one full-time equivalent employee for one calendar year.

[60] This assumes utility-scale storage prices for the year 2023 (see appendix).

5. CONCLUSIONS

As Colorado moves towards a carbon-free grid by 2040, energy storage will be necessary to meet peak demand. In addition, energy storage can provide many other critical services to the grid and bolster modest economic growth in the state. Currently, however, the results of our analysis show that energy storage deployment in the state is not expected to grow quickly in the coming decade without the support of smart policies and mandates. This is due to a combination of high upfront costs for batteries and the absence of a stable revenue stream through which storage can be compensated for the many services it provides to the grid. Though lithium-ion batteries are projected to decline in cost in the coming years, they are not expected to become cost-competitive with traditional generators prior to the late 2020s without supportive policy mechanisms. To ensure that the transition to renewable energy in the early years is done efficiently, the grid needs to be supported with energy storage, thus developers of energy storage would benefit from reduced market risk.

As such, Synapse recommends the following pathways to help encourage an earlier and deeper penetration of energy storage in Colorado:

1. Track development of the storage market to determine the necessity of an energy storage target or mandate in Colorado.
2. Develop a stable, transparent storage valuation protocol for utility resource planning based on best practices in leading states and wholesale markets.
3. Establish a process to identify and screen for opportunities for non-wires alternatives (including energy storage and other distributed energy resources) to meet load growth and reliability objectives.
4. Support innovation in storage ownership business models.
5. Continue to revise interconnection and planning processes to incorporate lessons learned from storage procurement and deployment.

In conjunction with the current ERP proceeding in Colorado, the above policy mechanisms are likely to reduce the barriers to storage deployment, thereby bolstering the state's transition to a renewable, carbon-free electric grid.

APPENDIX A: GRID MODELING STRUCTURE AND INPUTS

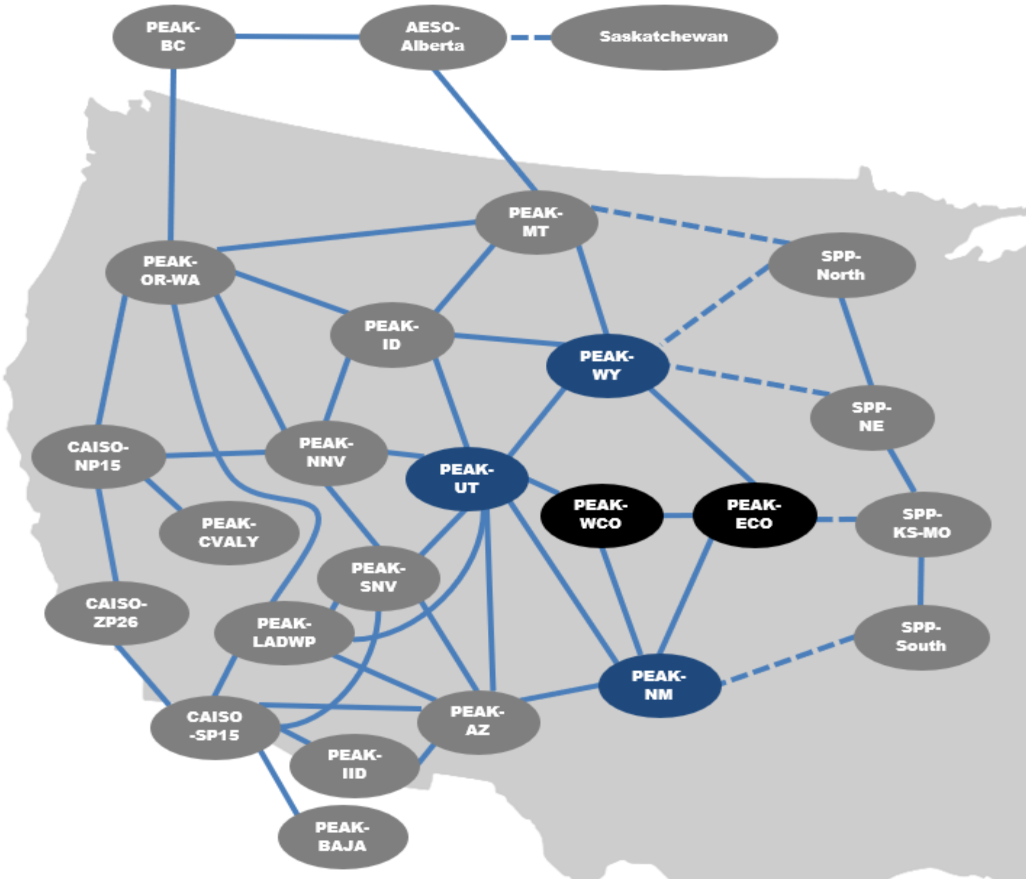
To assess the impact that increased storage penetration will have on the future electric grid in Colorado, Synapse used the EnCompass model developed by Anchor Power Solutions and the accompanying National Database created by Horizons Energy. EnCompass is a single, fully integrated power system platform that performs both production-cost and capacity-expansion modeling.[61] The primary model region includes Eastern and Western Colorado. Although this case study is focused on Colorado, for the purposes of electricity system modeling, it is important to model the greater electric system as well. As such, Synapse also modeled three adjoining regions with full unit-level operational granularity (shown in dark blue in Figure 24)—Wyoming, Utah, and New Mexico. Synapse modeled the remaining contract regions to represent the Western Interconnect (shown in grey in Figure 24).

In EnCompass, we explicitly modeled 12 years from 2018 through 2029, allowing us to both calibrate our model to recent historical operations in 2018 and provide projections through the next decade. EnCompass determines the optimal least-cost capacity build in each year.[62]

[61] For more information on EnCompass, see https://anchor-power.com/encompass-power-planning-software/.

[62] EnCompass allows for a wide variety of sub-annual temporal resolution. For this project, Synapse used the default, which is to model one on-peak and one off-peak day within each month, for each year, at a 24-hour resolution. On-peak periods occur Monday through Saturday, 7:00 am–11:00 pm Mountain time.

Figure 24. Modeling topology



Source: Horizons Energy National Database.

Load and demand-side forecast inputs

Evaluating the costs and benefits of storage on the electric system in Colorado requires an understanding of the annual energy and peak requirements. Increased load growth will impact the generation capacity build-out. As such, primary inputs include peak demand (MW) and annual energy (GWh) forecasts.

We used the load forecasts developed by Horizons Energy that rely on the NERC Long-Term Reliability Assessment for Western and Eastern Colorado, as well as the surrounding areas. These forecasts are shown in Table 4 below. By 2029, annual energy load is projected to increase by 11.6 percent for Eastern Colorado and 15.2 percent for Western Colorado from 2019; peak load is projected to increase by nearly 10.6 percent for East Colorado and 13.9 percent for Western Colorado from 2019.

Table 4. West Colorado energy and peak forecasts

Year	West Colorado		East Colorado	
	Annual Energy (GWh)	Summer Peak (MW)	Annual Energy (GWh)	Summer Peak (MW)
2019	13,263	2,238	53,506	9,533
2020	13,465	2,268	54,128	9,628
2021	13,667	2,297	54,750	9,723
2022	13,869	2,326	55,372	9,818
2023	14,070	2,356	55,994	9,913
2024	14,272	2,385	56,616	10,008
2025	14,474	2,414	57,238	10,103
2026	14,676	2,448	57,860	10,213
2027	14,878	2,482	58,482	10,323
2028	15,080	2,515	59,103	10,433
2029	15,282	2,549	59,725	10,542

Source: Horizons Energy & the NERC Long Term Reliability Assessment.

Existing, retiring, and new energy resources

Understanding exactly how Colorado's generation fleet may change, both through capacity additions and retirements, is integral to calculating the costs of storage deployment within the state.

Table 5 summarizes Colorado's existing resources as of 2019. Currently, Colorado has approximately 16 GW of capacity. Of that capacity, 42 percent is natural gas- or oil-fired and another 28 percent is coal-fired. Wind capacity comprises 19 percent of state capacity, and solar comprises 3 percent. Pumped-hydro storage and hydroelectric capacity each currently represent 4 percent of capacity.

Details on expected capacity additions in Colorado are shown in Table 6 and Table 7. Onshore wind resources make up the largest portion of planned capacity (60 percent). Solar PV resources make up 19 percent of planned capacity. Natural gas units make up 18 percent of the future capacity additions and storage makes up the remainder of the additions at 3 percent. Colorado expects ~1.67 GW of additional capacity between 2019 and 2023.

Table 8 shows planned capacity retirements in Colorado for the entire study period (out to 2029). Coal units comprise the largest portion of retirements at 68 percent, followed by gas units at 32 percent. Colorado expects to retire about 702 MW of capacity between 2019 and 2029.

Table 5. Summary of Colorado's existing capacity by resource type

Resource	Capacity (MW)	Capacity (%)
Natural Gas/Oil	6,662	42%
Coal	4,499	28%
Wind	3,106	19%
Hydro	687	4%
Pumped Storage	563	4%
Solar	461	3%
Other Renewables	29	0%
Total	**16,007**	**100%**

Source: Horizons Energy National Database and EIA Form 860-M. These numbers are subject to change based on the most up-to-date EIA and Horizons Energy data.

Table 6. Colorado expected capacity additions by resource type

Resource	Capacity (MW)	Capacity (%)
Wind	1000	60%
Solar	326	19%
Gas	301	18%
Storage	50	3%
Total	**1,677**	**100%**

Source: EIA Form 860-M and Public Service Company of Colorado 2016 Electric Resource Plan. Based on the "Preferred ERP" portfolio outlined in Public Service Company of Colorado (Xcel Energy), 2016 Electric Resource Plan, 120-Day Report Public Version, Proceeding 16A-0396E, June 6, 2018, Page 31. http://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_744921.

Table 7. Colorado planned capacity additions for 2019 to 2020 at a unit level

PLANT	TYPE	CAPACITY (MW)	ADDITION DATE	UTILITY
Trishe Wind Colorado	Wind	30	2019	Trishe Wind Colorado
Highland Park Project	Wind	181	2020	Clear Creek Power
Additional Planned Resources	Wind	1131	2023	Xcel Energy
Bar D	Solar	4	2019	Cypress Creek Renewables
Additional Planned Resources	Solar	707	2023	Xcel Energy
Additional Planned Resources	Storage	275	2023	Xcel Energy
Additional Planned Resources	Natural Gas	383	2023	Xcel Energy

Source: EIA Form 860-M and Public Service Company of Colorado 2016 Electric Resource Plan. Based on the "Preferred ERP" portfolio outlined in Public Service Company of Colorado, 2016 Electric Resource Plan, 120-Day Report Public Version, Proceeding 16A-0396E, June 6, 2018, Page 31. http://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_744921.

Table 8. Colorado planned capacity retirements (2019-2029)

Plant Name	Resource Type	Capacity (MW)	Addition Date	Utility
Craig (CO):1	Coal	428	2025	Tri-State G & T Assn, Inc
Nucla:1	Coal	12	2022	Tri-State G & T Assn, Inc
Nucla:2	Coal	12	2022	Tri-State G & T Assn, Inc
Nucla:3	Coal	12	2022	Tri-State G & T Assn, Inc
Nucla:ST4	Coal	64	2022	Tri-State G & T Assn, Inc
Comanche: 1	Coal	325	2022	Xcel Energy
Comanche: 2	Coal	335	2025	Xcel Energy
Alamosa:CT1	GT	13	2022	Xcel Energy
Alamosa:CT2	GT	14	2026	Xcel Energy
Fort Lupton:GT:44.7 MW(2)	GT	89	2026	Xcel Energy
Fruita:1	GT	15	2026	Xcel Energy
Valmont:6	GT	43	2026	Xcel Energy

Source: Horizons Energy National Database and Public Service Company of Colorado 2016 Electric Resource Plan, Volume 2. Public Service Company of Colorado (Xcel Energy) 2016 Electric Resource Plan, Proceeding 16A-0396E, May 27, 2016. http://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_session_id=&p_fil=G_744921.

Generic unit additions

The planned unit additions are not sufficient to meet the future energy demands within Colorado. As such, we defined a set of generic generating units that EnCompass can choose to build to meet energy, peak, and reserve margin requirements and to comply with state legislation and regulations. We allowed EnCompass to construct utility-scale solar, onshore, and battery resources (see Table 9), as well as conventional combined cycle, combustion turbine, and internal combustion power plants (see Table 10).

Table 9. Capacity increments for clean energy resources in Colorado

Resource	Capacity (MW)
Onshore Wind	100
Utility Solar	20
Battery Storage	4
Residential Solar	0.005
Commercial Solar	0.3

Source: Horizons Energy National Database and NREL. Commercial system size taken from NREL: Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States, Current Drivers and Cost-Reduction Opportunities, February 2012. https://www.nrel.gov/docs/fy12osti/53347.pdf.

Table 10. Generic conventional natural gas unit additions characteristics

	Unit	Combined Cycle	Combustion Gas Turbine	Internal Combustion
Winter Capacity	MW	702	237	85
Summer Capacity	MW	645	178	65
Heat rate	Btu/kWh	6,736	9,800	8,500
Variable O&M	2018$/MWh	2.37	7.53	7.53
Fixed O&M	2018$/kW-yr	11.26	5.11	5.11
NO_X emissions rate	lbs/MMBtu	0.0075	0.0300	0.0700
SO_2 emissions rate	lbs/MMBtu	0.0000	0.0000	0.0000
CO_2 emissions rate	lbs/MMBtu	119	119	119

Source: Horizons Energy National Database.

Renewables and storage

To meet the future energy demands and the policy goals of Colorado's current and proposed RES, renewable and storage resources must comprise a large portion of the state's future capacity additions. As such, storage and renewable energy cost and operational parameters are a central input for this modeling exercise.

These parameters include available capacity (in MW), resource characteristics (e.g., annual average capacity factors, capacity credits, and output profiles), and costs (including up-front costs, tax incentives, and fixed and variable operating costs).[63] We used cost and performance data from public sources for both existing and new renewable resources. This list includes:

- *Lazard Levelized Cost of Storage, v 4.0, November 2018* for cost of battery storage;[64]
- *NREL Annual Technology Baseline 2018* for cost of utility-scale solar, utility-scale wind and distributed solar PV; and[65]
- Regional hourly wind and solar shapes developed by Horizons Energy.

Table 11 and Table 12 show capital cost and fixed operating cost assumptions for generic renewable units available in this analysis. Variable operating costs are assumed to be negligible. We only included costs for utility-scale lithium-ion and flow batteries (vanadium and zinc), as these technologies are currently competitive and are likely to continue experiencing cost declines over time.

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[63] We used the Horizons National Database standard assumptions for financing (including assumptions on Capitalization Debt, Debt Interest Rate, Income Tax Rate, ROE, Insurance Rate, Property Tax Rate, AFUDC Rate, and CWIP). These inputs are based on traditional utility financing structures. Horizons also includes assumptions around the ITC for solar resources.

[64] See https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf. Battery cost declines are based on a blended trend between Lazard and the Horizons Energy National Database.

[65] See https://atb.nrel.gov/.

Table 11. Renewable and storage capital costs (2019 $/kW)

Year	Utility Battery			Utility PV + Storage		Utility Solar	Residential Solar	Commercial Solar	Onshore Wind
	Lithium	*Zinc*	*Vanadium*	*Battery*	*Solar*	*Average*	*Average*	*Average*	*Average*
2019	$1,359	$1,665	$1,682	$1,712	$1,196	$1,546	$3,592	$2,513	$1,645
2020	$1,226	$1,403	$1,468	$1,544	$1,077	$1,420	$3,202	$2,318	$1,632
2021	$1,105	$1,183	$1,281	$1,392	$984	$1,322	$2,938	$2,192	$1,620
2022	$997	$998	$1,117	$1,256	$913	$1,252	$2,793	$2,070	$1,608
2023	$924	$841	$975	$1,164	$885	$1,238	$2,703	$2,003	$1,597
2024	$856	$709	$851	$1,078	$857	$1,223	$2,613	$1,937	$1,587
2025	$793	$598	$742	$999	$831	$1,209	$2,523	$1,871	$1,577
2026	$735	$504	$648	$925	$805	$1,195	$2,433	$1,804	$1,567
2027	$681	$425	$565	$857	$780	$1,180	$2,343	$1,738	$1,558
2028	$631	$358	$493	$794	$755	$1,166	$2,254	$1,672	$1,550
2029	$573	$296	$422	$736	$731	$1,152	$2,164	$1,606	$1,542

Source: Utility battery costs and paired resources are sourced from Lazard (2018). All other values sourced from NREL ATB (2018).

Table 12. Renewable and storage fixed operating costs (2019 $/kW-year)

Year	Lithium	Flow	Utility Solar	Residential Solar	Commercial Solar	Onshore Wind
2019	$6	$8	$12	$21	$17	$54
2020	$6	$9	$11	$19	$16	$53
2021	$7	$9	$10	$17	$15	$53
2022	$7	$9	$10	$17	$14	$52
2023	$7	$9	$10	$16	$14	$52
2024	$7	$9	$10	$16	$14	$52
2025	$7	$10	$10	$15	$13	$51
2026	$7	$10	$10	$15	$13	$51
2027	$7	$10	$10	$14	$12	$51
2028	$8	$10	$9	$14	$12	$50
2029	$8	$10	$9	$13	$11	$50

Source: Utility battery costs sourced from the Energy Storage Technology Assessment (2017) prepared for Public Service Company of New Mexico.[66] *All other values from NREL ATB (2018).*

Self-generation from cooperatives

At present, the Colorado cooperatives have signed long-term contracts with Tri-State G&T that allow the cooperatives to generate a maximum of 5 percent of their total consumption through their own generating units. The Carbon Price Case scenario assumes that the "self-generation" from cooperatives will begin at 4 percent of their total consumption in 2018, increase to 5 percent by 2019, and remain at 5 percent for the remainder of the study period. Within the scenario, the remaining generation is purchased from Tri-State G&T. In the Increased Coop Self-Generation Scenario, Synapse assumes that the self-generation limit increases by 1 percent of total coop consumption beginning in 2020, resulting in a self-generation limit of 15 percent by 2029. All remaining generation continues to be purchased from Tri-State G&T.

Renewable portfolio standard

If a state has an RES policy in place, some portion of future electricity generation must come from renewable resources. The Colorado RES has three tranches: one for IOUs, one carve-out for distributed generation, and one for municipal or cooperative utilities. Table 13 below shows the current Colorado

[66] Public Service Company of Colorado, Energy Storage Technology Assessment, November 2017, https://www.pnm.com/documents/396023/1506047/11-06-17+PNM+Energy+Storage+Report+-+Draft+-+RevC.pdf/04ca7143-1dbe-79e1-8549-294be656f4ca

RES schedule.[67] We relied on the Horizons National Database for RES assumptions in all surrounding regions.

In the RES Scenario, annual renewable energy generation requirements increase. For IOUs, the RES requires that 75 percent of total electricity sales come from RES eligible technologies by 2029. Similarly, for municipalities and cooperatives, the RES requirement increases to 30 percent of total sales. Table 13 and Table 14 show RES requirement assumptions under the Carbon Price Case scenario and the RES Scenario.

Table 13. Colorado RES under Carbon Price Case scenario (% of electricity sales)

Year	IOU Requirement	DG Requirement for IOUs	Coop/Muni Requirement
2019	20.0%	2.0%	6%
2020	30.0%	3.0%	10%
2021	30.0%	3.0%	10%
2022	30.0%	3.0%	10%
2023	30.0%	3.0%	10%
2024	30.0%	3.0%	10%
2025	30.0%	3.0%	10%
2026	30.0%	3.0%	10%
2027	30.0%	3.0%	10%
2028	30.0%	3.0%	10%
2029	30.0%	3.0%	10%

Source: dsireUSA.org.

[67] Eligible Technologies include Geothermal Electric, Solar Thermal Electric, Solar Photovoltaics, Wind (All), Biomass, Hydroelectric, Landfill Gas, Wind (Small), Anaerobic Digestion, Fuel Cells using Renewable Fuels Recycled Energy, Coal Mine Methane (if the PUC determines it is a greenhouse gas neutral technology), Pyrolysis of Municipal Solid Waste (if the Commission determines it is a greenhouse gas-neutral technology).

Table 14. Colorado RES under the Expanded RES scenario

Year	IOU Requirement	DG Requirement for IOUs	Coop/Muni Requirement
2019	20.0%	2.0%	6%
2020	30.0%	3.0%	10%
2021	35.0%	3.0%	12%
2022	40.0%	3.5%	15%
2023	45.0%	3.5%	18%
2024	50.0%	4.0%	20%
2025	55.0%	4.0%	22%
2026	60.0%	4.5%	25%
2027	65.0%	4.5%	28%
2028	70.0%	5.0%	30%
2029	75.0%	6.0%	30%

Note: The Coop/Muni requirement is for cooperatives and municipal utilities with fewer than 100,000 customer electric meters. There is a different requirement for cooperatives and municipal utilities with 100,000 or more meters.

Carbon Price

Based on the recent passing of the Sunset Bill, Synapse included the resource planning carbon price in the Carbon Price Case and both policy scenarios. The carbon price comes into effect in 2020 at $46/short ton and increases by 2 percent each year (Table 15).[68]

[68] Colorado Senate Bill 19-236: https://leg.colorado.gov/sites/default/files/documents/2019A/bills/2019a_236_enr.pdf.

Table 15. Annual carbon prices for all scenarios

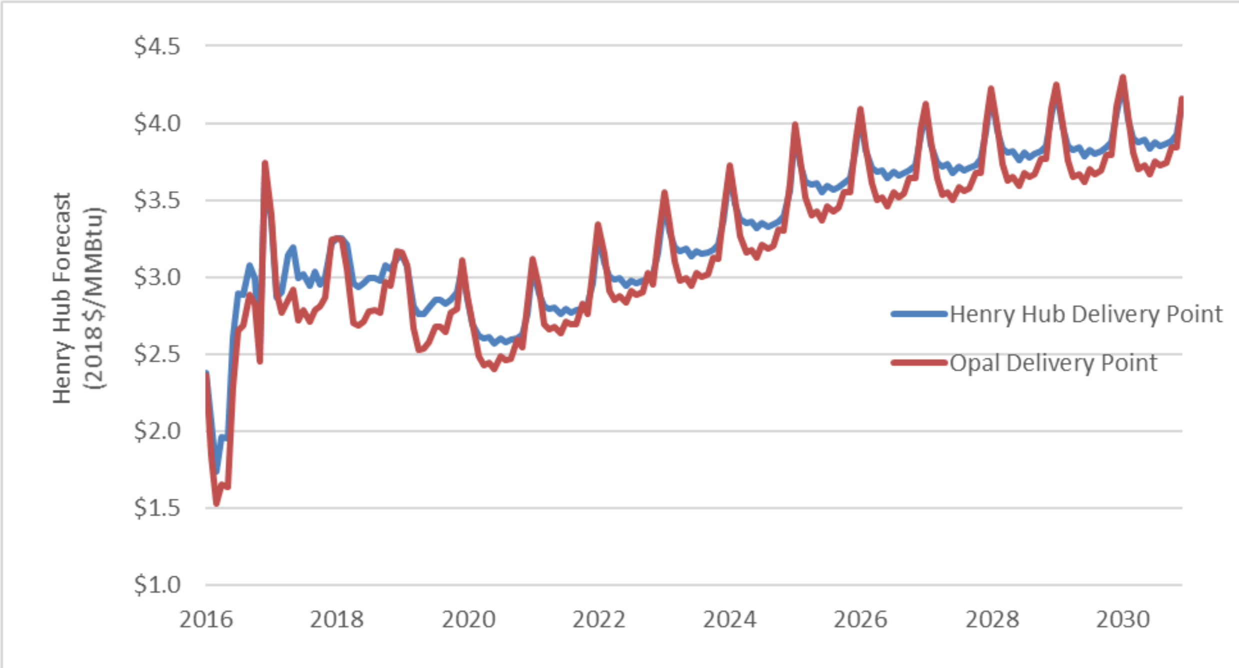
Year	Carbon Price (Nominal $/short ton)
2019	-
2020	$46.00
2021	$49.00
2022	$50.00
2023	$53.00
2024	$55.00
2025	$58.00
2026	$60.00
2027	$63.00
2028	$66.00
2029	$68.00

Natural gas prices

Within EnCompass, Synapse set both historical and projected natural gas prices. The natural gas prices are projected using historical gas prices for Henry Hub which are derived from Platts. Forecasted prices through 2020 are set using NYMEX prices. From 2021 to 2022, Synapse used a blend of NYMEX prices and the 2019 Annual Energy Outlook (AEO) projections until the two forecasts reach agreement. For 2023 onward, we exclusively used AEO projections. Figure 25 shows the projected forecast out to 2030, when natural gas prices reach over $5/MMBtu at their annual maximum.[69]

[69] Annual Energy Outlook 2019, Projection Tables for Side Cases.

Figure 25. Historical and projected natural gas prices



Source: Historical Henry Hub prices (Platts), NYMEX future gas prices, and Annual Energy Outlook 2019.

APPENDIX B: BTM STORAGE MODELING ASSUMPTIONS

Key Inputs and Sources

Synapse broke out input parameters into the following categories: battery system specifications and costs, program design attributes, and avoided costs. For the model we are using a 5 kW/13.5 kWh battery system that has a 90 percent round trip efficiency and depth of discharge of 100 percent.[70] Each battery unit costs $6,700, excluding supporting hardware ($1,100), and we assumed installation costs to be $2,000 per installation.[71] In total, the cost of equipment and installation for a single residential battery participant is $9,800. Commercial participants have a lower cost per unit at $18,500 for both batteries or $9,250 per battery due to the fixed cost of supporting hardware. Table 16 details all other battery specification assumptions.

For each battery system we have set a limit on the amount of energy available for demand response participation to 50 percent of the available usable energy (reserves availability), based on Xcel's program design. While Xcel did not specify event lengths in its pilot description, a two-hour event would allow each battery system to discharge at its maximum rate for a single hour and then at a lower rate for the second hour to reach the 50 percent reserves availability target. This event length allows us to capture the maximum capacity savings during a peak hour while also reducing energy consumption during the second hour.

Table 16. Assumed battery specifications

Input	Units	Single	Double
Number of Battery Units per Customer	#	1	2
Usable Energy	kWh	13.5	27
Continuous Capacity	kW	5	10
Lifetime	Years	10	10
Depth of Discharge (DOD)	%	100	100
Round Trip Efficiency	%	90	90
Reserves Availability (Used for DR)	kWh	6.75	13.5
Battery Cost	2019 $	6,700	13,400
Hardware Cost	2019 $	1,100	1,100
Installation Cost	2019 $	2,000	4,000
Operation/Maintenance Cost	2019 $	0	0

[70] Battery specifications are modeled after the Tesla Powerwall 2.

[71] While installation costs will vary for each customer, Tesla cites a range between $1,000–$3,000 for residential installation costs. We have chosen $2,000 to represent the average installation cost and assumed costs would be doubled for small commercial participants due to the additional battery.

Program design inputs include program costs as well as participant counts (Table 17). To calculate total program costs for small commercial participants, which are not included in Xcel's battery pilot, we applied Xcel's average program costs for residential participants and doubled the incentive for the double-battery scenario.

Table 17. Xcel Battery Demand Response Pilot Program costs

Input	Units	Single	Double
Pilot Participants (Year 1)	#	250	250
Total Participants	#	500	500
Administration and Program Delivery	2019 $ / year	128,006	128,006
Marketing and Customer Education	2019 $ / year	3,116	3,116
Participant Rebates and Incentives	2019 $ / year	153,974	307,949
Measurement and Verification (M&V)	2019 $ / year	56,005	56,005
Real Discount Rate	%	0.47	0.47
Pilot Length	years	2	2
Non-Incentive Length	years	8	8

The remaining inputs include both the T&D avoided costs and greenhouse gas emission reductions. Avoided T&D costs between 2020 and 2029 were taken directly from Xcel's DSM study and averaged to yield the values in Table 18. Greenhouse gas emissions were calculated using the U.S. Energy Information Administration's emissions rates for the state of Colorado.[72]

Table 18. Avoided cost assumptions

Input	Units	Value
Avoided Transmission Costs	2019 $ / kW	9.73
Avoided Distribution Costs	2019 $ / kW	2.65
Energy Line Losses	%	7.69
NO_x	Short ton / MWh	0.000509
SO_2	Short ton / MWh	0.000289
CO_2	Short ton / MWh	0.731

Calculations

Using our input parameters, we modeled hourly usage for both a single- and double-battery residential customer over a year. The battery was set to charge during off-peak hours (1:00–5:00 AM) and discharge between peak hours (4:00–6:00 PM). In reality, peak pricing times in Colorado are from 2:00–

[72] Colorado emissions rates from EIA. State-wide emissions may differ slightly from Xcel specific rates. https://www.eia.gov/electricity/state/colorado/.

6:00 PM, but for the purpose of maximizing battery cost-effectiveness, we chose to discharge the batteries during a two-hour event.[73] Our battery cycling was limited in two ways to match Xcel's pilot description. The battery system was set to discharge only 50 times during the summer months and 50 during the winter at half of the battery's available usable energy. For a single-battery residential participant, only 6.75 kWh was available to be used in a demand response event. In order to maximize capacity savings, we modeled each battery to discharge at its continuous capacity (5 kW) for the first hour of the peak and then at a lower rate (1.75 kW) to meet the reserves availability during the second hour. We calculated capacity savings by taking the maximum savings (discharge kW) and multiplying by the number of participants. Since only 250 participants were involved in the first year of the pilot followed by 500 for the second year and remaining usable life of the battery, we took a weighted average of the delivered capacity. We calculated energy savings for both on- and off-peak in summer and winter by taking the sum of savings and multiplying by the number of participants. Energy was similarly calculated to account for the different number of participants for the pilot and post-pilot periods.

System benefits including avoided energy, capacity, T&D costs were calculated using annual capacity and energy savings.[74] We took the net present value of the cumulative 10 years of capacity and energy prices then multiplied that by the quantity of energy or capacity savings. We derived annual energy prices from the production cost modeling done in EnCompass, while we took capacity prices from Xcel's 2016 ERP. A capacity price of $2.79/kW-year was set through 2023 and increased to the economic carrying charge or cost of a generic combustion turbine at $5.55/kW-year.[75] T&D costs, $8.76/kW and $2.38/kW respectively, were averaged over the 10-year life of the study and discounted to today's dollars. On- and off-peak energy pricing differed under the three policy scenarios, however capacity prices stayed constant.

Synapse calculated total costs in two parts to account for pilot and post pilot costs. Administration, marketing, incentive, and M&V costs from Table 17 were multiplied by the pilot program length, yielding a total pilot cost of approximately $680,000 for single-battery and about $990,000 for double-battery residential participants. We assumed there would be post-pilot costs for the future life of the battery (eight years) including program delivery and administration costs as well as M&V costs. Overall the total post-pilot costs were approximately double the pilot costs at $1.4 million. While we did not incorporate participant costs into the BCR, we included them in Table 19. One-time costs include the battery as well as installation and hardware. Finally, we calculated the total net benefits over the battery lifetime by subtracting total utility costs from total energy, capacity, and T&D costs.

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[73] Xcel peak pricing periods https://www.xcelenergy.com/billing_and_payment/understanding_your_bill/residential_rate_plans/time_of_use_pricing/time_of_use_pricing_how_it_works.

[74] Avoided T&D costs outlined on pg. 362 of Xcel's DSM report. https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/DSM-Plan.pdf.

[75] Xcel electric resource plan outlining future capacity costs. https://www.xcelenergy.com/staticfiles/xe/PDF/Attachment%20AKJ-2.pdf.

Table 19. Total participant costs including battery system and incentives (2019 $)

Input	Single-Battery	Double-Battery
One-Time Costs	$4,900,000	$9,250,000
One-Time Incentive	$(307,949)	$(615,897)
Total Costs	$4,592,052	$8,634,103

Source: Synapse calculations.