FLEXIBLE, CLEAN INDUSTRY AND SUSTAINABLE ENERGY POWER STRONG ECONOMIES

A case study in Pueblo, Colorado

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EXECUTIVE SUMMARY

As electricity grids around the world transition to clean energy, the electrification of other sectors such as buildings, transportation, and industry continue to add electricity demand. Intuitively, more demand would make cleaning up the grid harder—more infrastructure, more power plants, and greater complexity. But innovative technology and well-designed policy can enable electrification of these other sectors, particularly industry, to aid in the electricity system's transition to clean resources.

This paper explores an emerging approach to transform cheap, clean renewable generation by co-locating with symbiotic new industries that can use electricity flexibly and how it could apply in Pueblo, Colorado. The combined resource creates a more dispatchable and reliable electric grid asset while at the same time providing an opportunity for host communities to capture more of the economic benefits of the energy transition. We refer to this approach as an "energy park."

Instead of having to curtail or export renewable generation in times of high electricity production, the flexible industrial technologies included in this new approach absorb that excess electricity for local industrial use and can even provide some of it back to the grid during times of need, serving as a form of long-duration storage. Flexible industries benefit from participation in the energy park because they can access lower electricity prices by primarily using electricity during times of lower demand. Examples include thermal batteries, which can convert electricity to heat for direct use in many industrial processes that require heat, or electrolytic hydrogen facilities that use electricity to make hydrogen out of water. Hydrogen can then be used to produce commodities like ammonia or sustainable aviation fuel. In an energy park, cheap power from excess clean energy stimulates a diverse set of local business activities with economic benefits, which are wider, deeper, and more sustainable than benefits that depend on hosting a single large electricity generator.

The purpose of this paper is to flesh out how combining flexible industrial technologies, referred to as "flexible loads," with solar and wind generation and short-duration batteries all located in proximity can create a resource that is more than the sum of its parts and that helps solve key reliability challenges for any grid.

As an example, we model the operational profile and benefits of a combination of renewable generation, short-duration batteries, and flexible loads (both serving local industrial needs and acting as long-duration storage) in an energy park located in Pueblo, Colorado. Because Pueblo hosts the Comanche Unit 3 coal-fired generating unit, which is slated for retirement in 2031, it is an instructive example of an energy park for several reasons.

First, the community surrounding the coal plant relies heavily on the tax revenue paid by the current plant's owners, primarily Xcel Energy, to fund county coffers as well as diverse services like schools and libraries. Attraction of new industries via cheap, clean electricity would create new economic opportunities for Pueblo while avoiding the tax revenue cliff that Comanche Unit 3's retirement presents.

Second, Pueblo is well connected to existing grid infrastructure, meaning an energy park centered on Pueblo would be optimally located to both export and import power, depending on the needs of the wider grid. Further, the existing coal plant's infrastructure could support the energy park in terms of both interconnection to the grid and potential re-use of the plant's turbine or other infrastructure.

Third, the renewable energy potential in Pueblo is strong—the solar resource matches some of the highest capacity factors in the United States, and a mix of wind resources both in-county and from places south and east of Pueblo can provide a steady and complementary balance to solar in the generation portfolio. The surplus part of the renewable energy thus generated could be offered cheaply to industrial customers, while the underlying profile provides a firm resource for the grid, especially serving denser populations like the Colorado Springs and Denver metro areas.

This paper is not meant to be an exhaustive grid modeling exercise but instead offers an initial vision for how an energy park spread at sites across Pueblo County and nearby regions and utilizing infrastructure from the Comanche coal-fired power plant could provide even better support for the grid than the original coal plant, while generating replacement jobs and tax revenue for the surrounding community of Pueblo.

We make three key findings:

1. **An energy park in Pueblo can be a highly reliable grid resource and produce energy for the local economy.**

The modeled energy park meets a corrected version of Comanche Unit 3's behavior with 99 percent reliability—better than Comanche Unit 3 itself, which was only 90 percent reliable when compared to this corrected resource (see Appendix A). Enough electricity is exported from the energy park to match corrected Comanche behavior while keeping over 40 percent of the energy generated in Pueblo County to drive industrial activity with bargain-priced energy.

2. **An energy park in Pueblo can generate high-quality permanent jobs and tax revenue.**

The energy park could generate more than $40 million in annual property taxes in Pueblo County and could create more than 350 permanent jobs directly associated with the energy park—even without accounting for additional jobs at industrial heat facilities. Importantly, jobs and tax revenue could start accruing even before the plant retires. Because the energy park would re-use infrastructure at the existing Comanche site, some of the jobs at the site could even be retained.

3. **An energy park in Pueblo would be much cheaper for electricity customers in Colorado than a comparable "clean firm" resource.**

The overall cost of the energy park is about 30 percent lower than the cost of a clean firm energy resource in the form of a small modular nuclear reactor like one that proposed as a replacement for Comanche Unit 3. More importantly, because rates from industrial customers pay for a significant fraction of the capital investment into the energy park, costs to electricity customers are roughly halved compared to alternative clean firm resources like a small modular reactor.

Additional benefits of the energy park include reduced development risk because the components are mostly technologies that are widely deployed commercially today, and though maximum reliability benefits accrue with the entire portfolio in place, it provides incremental value to the grid at all steps of project development. While operational complexity is increased as compared to a single large generator, operational resilience is also increased due to locational diversity of the portfolio as compared to a single large generator. An energy park as imagined in paper would keep energy in Pueblo to drive new economic development in the form of jobs and property tax, while providing support needed for the broader Colorado electricity grid, and emissions reductions from industrial processes – a rare win-win-win.

WHAT IS AN ENERGY PARK?

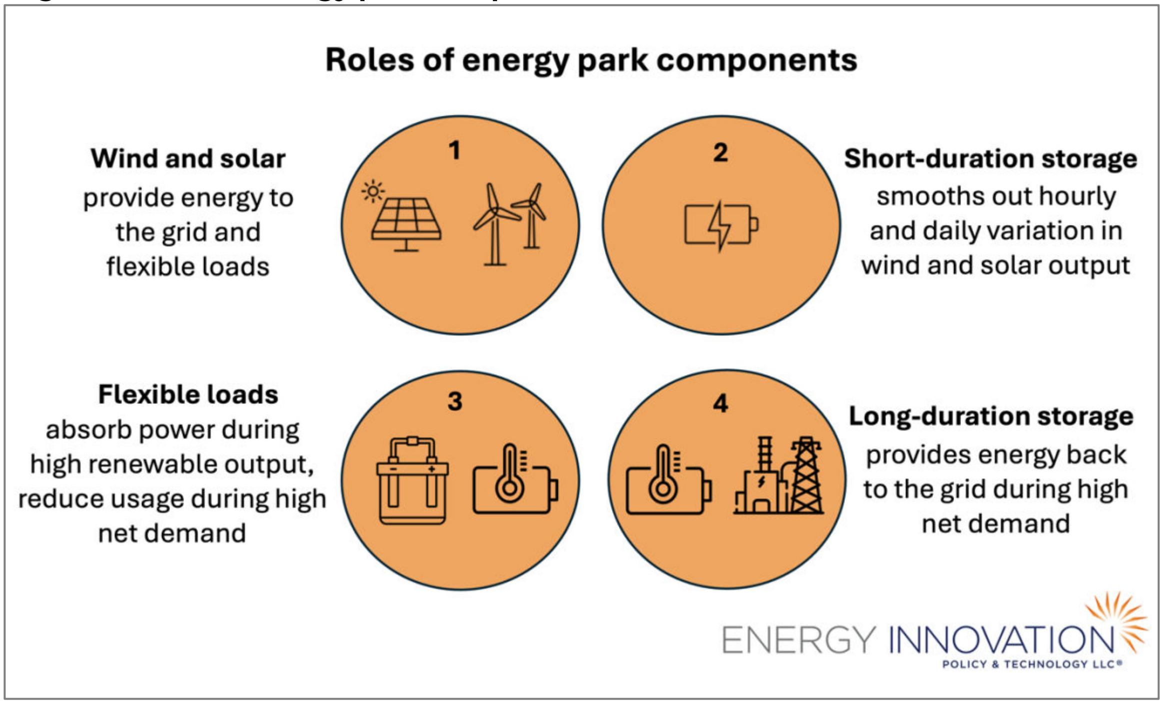
An energy park as we envision here consists of four main components working in concert to support the electricity grid and its users. The four components are 1) renewable energy (primarily wind and solar), 2) short-duration battery storage, 3) flexible industrial customers that can use electricity when wind and solar generation are high but ramp down when available output is low, and 4) long-duration energy storage in the form of additional flexible technologies that can both store energy and reconvert it to electricity.

For Pueblo, these components would be sited primarily in-county, using the existing Comanche coal plant substation as a primary hub for coordination and interconnection, but with projects spread across the city and county. With some incremental high-voltage line capacity, some of the wind resources could be sited out-of-county, in further southeast Colorado, but still work in concert with the other parts of the energy park.[i]

These resources can be constructed over time, building up the energy park into a grid resource that is even more reliable and flexible than the original coal plant and diversifying the sources of tax revenue and job base in Pueblo.

[i] While siting wind resources out of county would reduce property tax revenue for Pueblo, the majority of tax revenue from the energy park would come from other components, particularly new industries.

Figure 1. Roles of energy park components



In more detail, we model how the four primary components of an energy park can come together in Pueblo to mimic a target 500 megawatt (MW) -resource hourly dispatch as follows:

1. The first component consists of 2,000 MW of in-county solar projects and a 1,600 MW combination of in-county wind and out-of-county wind projects, providing almost triple the total annual energy required to meet the target energy generation profile for a 500 MW resource.
2. The second component includes 500 MW/2,000 megawatt-hour (MWh) of short-duration battery storage to smooth out daily and hourly variation in solar and wind output. Since the battery's maximum power matches that of the target 500 MW resource, the energy park can produce any desired output if enough energy is stored.
3. The third component is flexible industrial-scale electricity consumers. This includes two modeled technologies: thermal batteries that draw as much as 800 MW of electricity and provide up to 200 MW of steady state thermal output to high-temperature heat users in Pueblo, and 400 MW of flexible electrolyzers that create hydrogen for further conversion into green ammonia or sustainable fuels. This component improves the reliability and economics of the energy park as an electric generation resource because more wind and solar can be integrated without increasing curtailment or surplus energy. It also allows industrial consumers in Pueblo to consume more power from the energy park

than the park exports to the rest of the state. Electricity is provided to the thermal batteries about 25 percent of the time, and to the electrolyzers 60-70 percent of the time.

4. The fourth component is long-duration storage. For this purpose, we model 1,600 MW of thermal batteries in a different configuration from above: rather than serving industrial heat customers across Pueblo, these thermal batteries are located on-site at the Comanche power plant. They store heat exclusively to later drive a standard steam turbine. The maximum heat output of these batteries is 400 MW of steam, which can provide up to 160 MW of electric power, assuming a conservative 40 percent turbine efficiency. While less efficient on a round-trip basis, these thermal batteries are cheaper than the 4-hour batteries mentioned above and can provide power for up to 18 hours at full charge, for a total of 2,880 MWh stored energy that could be used by the grid during periods of low wind and solar production. The waste from low round-trip efficiency is offset by the fact that these thermal batteries primarily store power that would otherwise go unused or un-exported by the energy park.

These orchestrated energy park components provide significant reliability when compared to an idealized version of the electric generation of Comanche Unit 3, while also providing over 40 percent of the park's energy to drive clean industrial activity in Pueblo.

ENERGY PARK COMPONENTS TODAY

The Pueblo renewable energy park described in this paper would be a new combination of resources, but all the components are already in various stages of commercialization.

Short-duration energy storage orchestrated with wind and solar

In Morrow County, Oregon, the Wheatridge Renewable Energy Facility is the first to integrate and orchestrate solar, wind, and batteries that can store up to 4 hours of energy at utility scale in one location.[1] In all, the facility encompasses 200 MW of wind power (with 200 MW more to come), 50 MW of solar power, and 30 MW of 4-hour batteries.[2] The facility spans 18 miles and is all connected to the grid at one substation, allowing this combination of resources to operate as a single unit. Because of the diversity of resources in the project, the facility can provide power even when a cloud shades the solar panels or wind speeds are low. The project's developer, NextEra Energy Resources, uses energy optimization software to charge and discharge the batteries, creating a stable output for the grid that is more than the sum of its parts.[3]

Flexible electrolytic hydrogen production

Ammonia production from clean hydrogen

Tax credits created by the Inflation Reduction Act (IRA) for clean hydrogen production are driving new industries in the U.S. The federal tax credit of $3 per kg of clean hydrogen can make it cost-effective to produce hydrogen from electrolysis, a process that uses electricity to split water molecules into hydrogen and oxygen. One of the biggest uses of hydrogen today is in ammonia production for fertilizer. As a result, companies are now aiming to produce clean ammonia at combined electrolyzer-fertilizer production plants, such as the Talus Renewables plant under construction in Iowa.[4] The plants are designed to run on variable power generation so they can time production to match wind and solar output. Colorado has an additional $1/kg tax credit[5] for clean hydrogen production, so long as the hydrogen is used for qualified uses, providing a further incentive to site such facilities within the state, if the electricity generation conditions are suitable. Qualified uses include hard-to-electrify end uses like green ammonia and sustainable aviation fuels.[ii]

Hydrogen co-located with renewable energy

In Texas, Intersect Power's Project Meitner[6] proposes flexible use of electricity at a similar scale to the energy park envisioned in this paper. The project aims to bring 400 MW of electrolyzers online, with 340 MW of solar and 460 MW of wind capacity to power the production of hydrogen. The project will be able to return electricity to the grid when power is needed and use clean hydrogen to make fuels on-site in the Texas panhandle. Because of the flexible use of on-site renewable resources, the electrolyzer will have access to cheap power that—alongside the IRA hydrogen tax credit—makes its hydrogen production cost-effective.

Thermal batteries

Thermal batteries are energy storage devices that convert electricity to heat and store the heat either for use by an industrial heat user or for reconversion into electricity at a later time. There are multiple types of thermal batteries, and they function primarily by running power through electric resistance heaters within a heat storage medium such as bricks, rocks, molten salt, or graphite. The batteries can take in electricity when wind and solar generation are high, store it, and output a steady stream of heat for an industrial customer, serving as a drop-in replacement for coal or gas boilers. They can

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[ii] Colorado is already heavily involved in partnerships centered on hydrogen electrolysis, green ammonia, and next generation fuels, e.g., https://www.nrel.gov/news/features/2023/nrel-teams-with-australias-fortescue-future-industries-on-a-colorado-innovation-center.html and https://www.newswire.ca/news-releases/hydrofuel-and-colorado-state-university-begin-1-5-million-us-green-ammonia-maps-project-868656448.html.

output heat at temperatures up to 1,700 degrees Celsius, making them a perfect fit for high-temperature, inflexible industrial heat needs.

Thermal batteries are already in use in the U.S., supplying a steady stream of heat to facilities like distilleries, plastic recycling facilities, and ethanol plants in multiple states.[7]

Long-duration energy storage

Thermal batteries can also be used as long-duration storage. In our example model, the use case is to have extra thermal batteries located adjacent to the old (or replacement) steam turbines at Comanche, where they reconvert stored heat into electricity by heating up high-pressure steam that can be used to turn a turbine. The advantage for modeling purposes is both one of simplicity—we can use a similar technology to that used for industrial heat delivery and use a steam turbine to produce electricity—and versatility because thermal batteries used this way can be backed up at a relatively low expense with a small boiler to provide extra energy when needed. This backup boiler can be fueled by small amounts of sustainable fuels like hydrogen or biogas, and even in the worst case where it burns unmitigated fossil gas, the emissions impacts are very small because the boiler is run efficiently and so infrequently.

There are also other ways to use thermal batteries to convert heat to power, such as by opening a window to the hot storage medium, which radiates heat as infrared light. Thermal photovoltaic cells can then capture that radiation and convert it back to electricity. In 2022, a U.S. Department of Energy study validated the use of Malta's Thermo-Electric Energy Storage system to cost-effectively convert a retired or retiring coal plant (or other steam turbine fossil generation unit) into a long-duration energy storage plant.[8] Such validation with earlier versions of thermal storage using molten salt to re-power coal plants is important, but the economics there are challenging. Next-generation technologies offered by companies such as Rondo, Antora, RedoxBlox, and Brenmiller will likely achieve significant cost improvements in the time frame proposed in this paper as they deploy and scale.

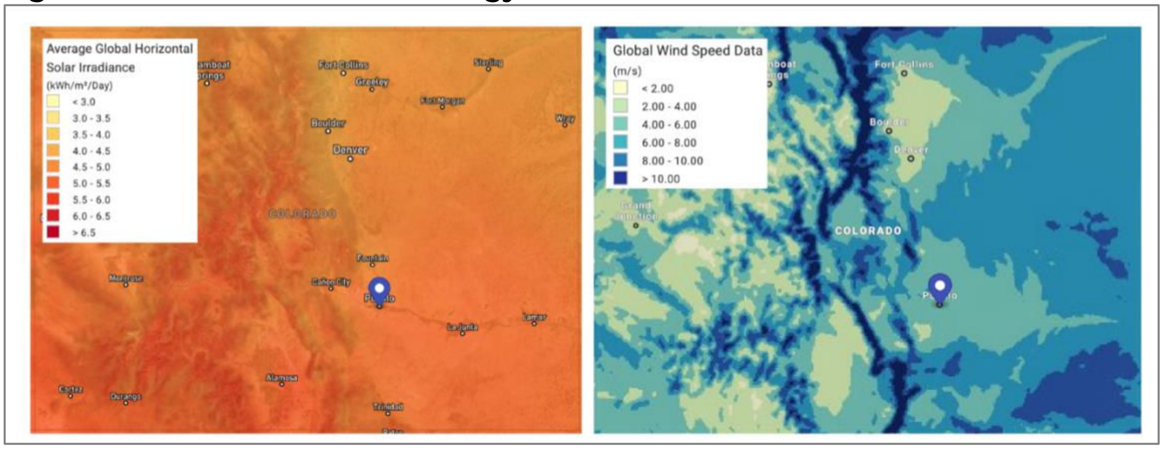
Xcel Energy is also testing other long-duration storage technology, like a 10MW/1,000 MWh iron air battery built by Form Energy at Comanche and other coal-fired power plant sites.[9] In our model, after we include the first three components (renewables, 4-hour batteries, and flexible loads), the single largest energy gap is just under 6,000 MWh over 60 hours. Half of that gap can be met with on-site thermal batteries at the Comanche plant configured for long-duration storage, but any other options for long-duration storage will work. Ultimately, the grid planner (in this case Xcel) must decide how much of this extra energy capacity would be beneficial inside the energy park versus utilizing other grid assets or demand response programs elsewhere. But in the end, the technical capacity to 100 percent mimic a reliable clean firm resource is a matter of cost/benefit analysis (an affordable one, we believe) and not a technical challenge.

ENERGY PARK IN PUEBLO

Boundaries of the energy park

Pueblo's location is ideal for a renewable energy park in multiple ways. First, there are strong renewable resources within Pueblo County—the solar resource is among the strongest in the state. Wind, too, has strong potential in the southeast and southwest part of the county, and even stronger potential in further southeast Colorado. Second, the high-voltage electricity grid in Pueblo is very well connected to other parts of the state. Therefore, the energy park could be built on an expanded footprint that encompasses both in-county and out-of-county resources, and electricity could be easily exported to or imported from other parts of the state when excess is generated.[iii] Third, there are strong existing industries in Pueblo that could take advantage of the energy park resources, and potential future sites for new industry at the PuebloPlex development at the former Pueblo Army Depot site 18 miles east of the Comanche power plant.

Figure 2. Colorado renewable energy resources



Source: National Renewable Energy Laboratory National Solar Irradiation Database[10] and Wind Resource Database[11]

This means that within Pueblo County, some energy park components could be located at the Comanche plant site, particularly a subset of the 4-hour batteries and thermal batteries used in the process of reconverting heat into electricity. However, other components could be sited miles away. Thermal batteries would likely be built on-site at industrial facilities that want to buy clean heat, with medium-voltage transmission lines bringing power directly to the batteries (or directly via existing high-voltage lines for the EVRAZ steel mill). Electrolyzers, too, could be sited a distance away from the Comanche plant. The PuebloPlex site, with its potential to select its utility

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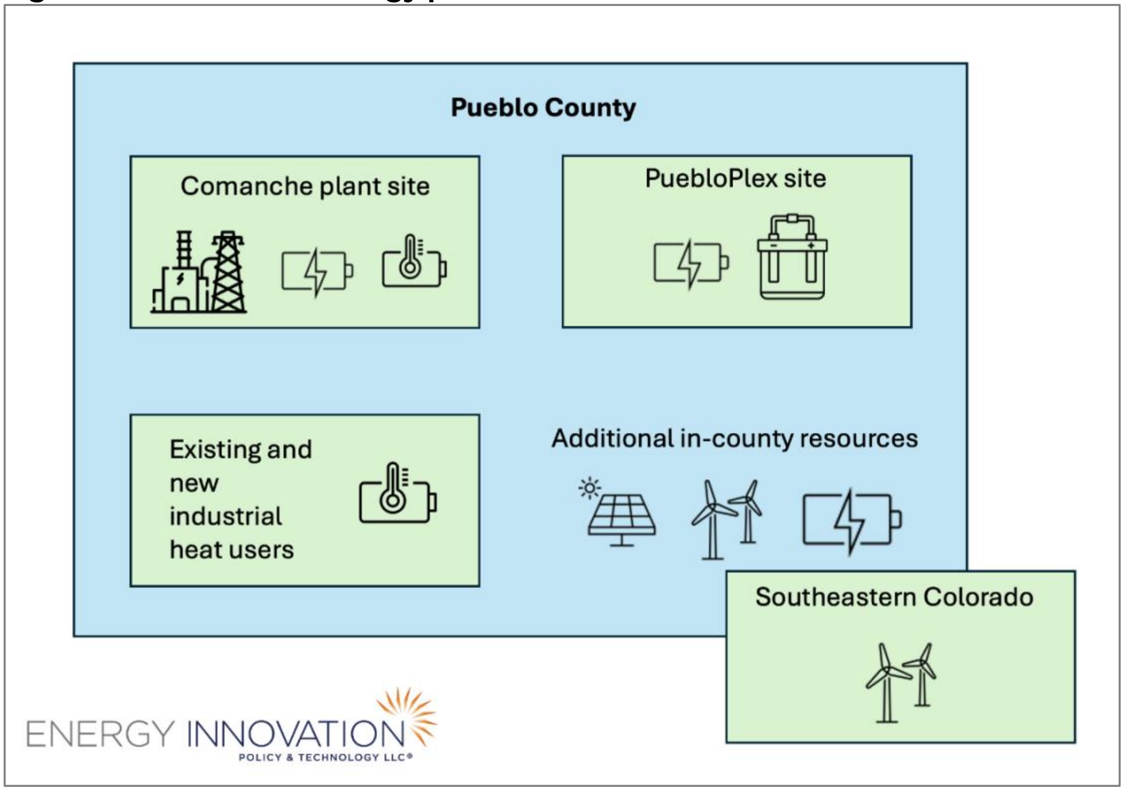
[iii] Additional transmission upgrades could be needed, particularly to access out-of-county resources, though we did not study that in this paper.

providers outside of the Black Hills electricity franchise in Pueblo, could provide space for the electrolyzers and associated infrastructure to convert clean hydrogen into other commodities such as ammonia. Like the thermal batteries, medium-voltage lines would run from electricity generation sources or other substations on the local high-voltage lines to the electrolyzer sites.

There are several existing industrial customers in Pueblo that could utilize thermal batteries for industrial heat. For example, while the EVRAZ steel mill is largely powered by solar electricity from the Bighorn Solar Project,[12] there are multiple processes within the plant that still use natural gas for heat. Other current industrial heat users include the GCC cement plant[iv] and the Collins Aerospace plant that manufactures carbon brakes for aircraft.

The energy park could support additional new industry beyond the electrolyzer, either by adding energy resources to serve new electrical loads, or new heat customers. New electrical loads could include data centers (see A B), while new heat customers could include a range of manufacturing facilities.

Figure 3. Schematic of energy park resource distribution



[iv] Decarbonizing cement is probably a second-generation use for thermal batteries, as this industry needs temperatures on the high end of what thermal batteries can achieve, and injecting heat directly into these processes requires more development compared to first-generation uses where a boiler is directly replaced.

Dynamics in Pueblo

The energy park also has two unique attributes that would help it fit into the Pueblo energy ecosystem. First, the use of thermal batteries for converting electricity into industrial heat means that Xcel may be able to sell energy from the energy park to existing businesses in Pueblo without running afoul of the Black Hills electricity franchise. Xcel already provides heat in the form of natural gas to Pueblo residents, so this would be a natural extension of its current jurisdiction. Second, the PuebloPlex provides an opportunity to site new industrial customers as Xcel builds out these new power resources, keeping more of the power generated within Pueblo and driving Pueblo's economic development instead of only exporting power to customers in other parts of Colorado.

MODELING RESULTS AND DISCUSSION

MODELING METHODOLOGY OVERVIEW

A main goal for this paper is to assess how an energy park in Pueblo would perform as a replacement resource for the Comanche power plant in terms of energy, capacity, property tax revenue, and jobs. The modeling is meant to be precise enough to illustrate the value of various energy park scenarios but is not meant to be comprehensive or to compete with more rigorous system-wide planning. Here, we present our methodology, key assumptions, and a summary of findings. Full modeling details are available in the appendix, along with additional scenarios.

Xcel currently owns a 500 MW portion of the 857 MW Comanche Unit 3, so we model a collection of resources that together represent a 500 MW resource that can be dispatched to match the behavior of Comanche Unit 3. An "ideal" 500 MW firm dispatchable resource is one that can both generate and consume power anywhere in the range up to the full 500 MW capacity in any given hour with no other constraints. Of course, no such resource exists, but the most valuable resource one could locate at the Comanche site would be able to consume, store, and generate power as a wholesale service.

For simplicity, instead of modeling the whole Public Service Company of Colorado (PSCo) grid, we have optimized the energy park portfolio dispatch around a target matching a corrected behavior for Comanche Unit 3 in the 2023 historical year (see Appendix A for details). Compared to the ideal dispatchable resource described above, the existing Comanche Unit 3 has a couple of drawbacks: it cannot absorb excess electricity from the rest of the grid, and it primarily runs between roughly 60 percent and 100 percent of its maximum output. We assume an energy park that can reliably produce power as needed within this range would fit the grid operator's needs for a firm resource at this location. The energy park's ability to perform above and beyond a coal plant by operating at wider output range and storing excess energy would be additional benefits.

We model the four components of the energy park described previously, including 1,600 MW wind and 2,000 MW solar, 500 MW short-duration (4-hour) battery storage, flexible loads including 800 MW of thermal batteries and 400 MW of flexible hydrogen electrolyzers that can absorb electricity, and a 1,600 MW thermal battery on-site at Comanche that can reconvert heat to electricity for additional reliability benefits. These resource capacities were selected based on initial estimates and selected scenario analysis, but were not analyzed in a capacity expansion model, meaning they could be further optimized (see Appendix B for details). We include model results for two additional scenarios in Appendix B, one that includes an inflexible load such as a data center, and one that relies on primarily long-duration storage for reliability benefits instead of flexible loads.

Our model dispatches these components over the course of a year, optimizing primarily to match the output of the energy park to an idealized version of Comanche Unit 3. See Appendix B for dispatch optimization details. Because the coal plant has historically been unreliable, with at least eight periods of unforced outages in our historical data year, we extrapolated its output to a generation profile with likely unscheduled outages removed, creating a "target profile" for the energy park that generates about 3,400,000 MWh of energy annually. This equates to a capacity factor of approximately 78 percent for a 500 MW resource.

KEY FINDINGS

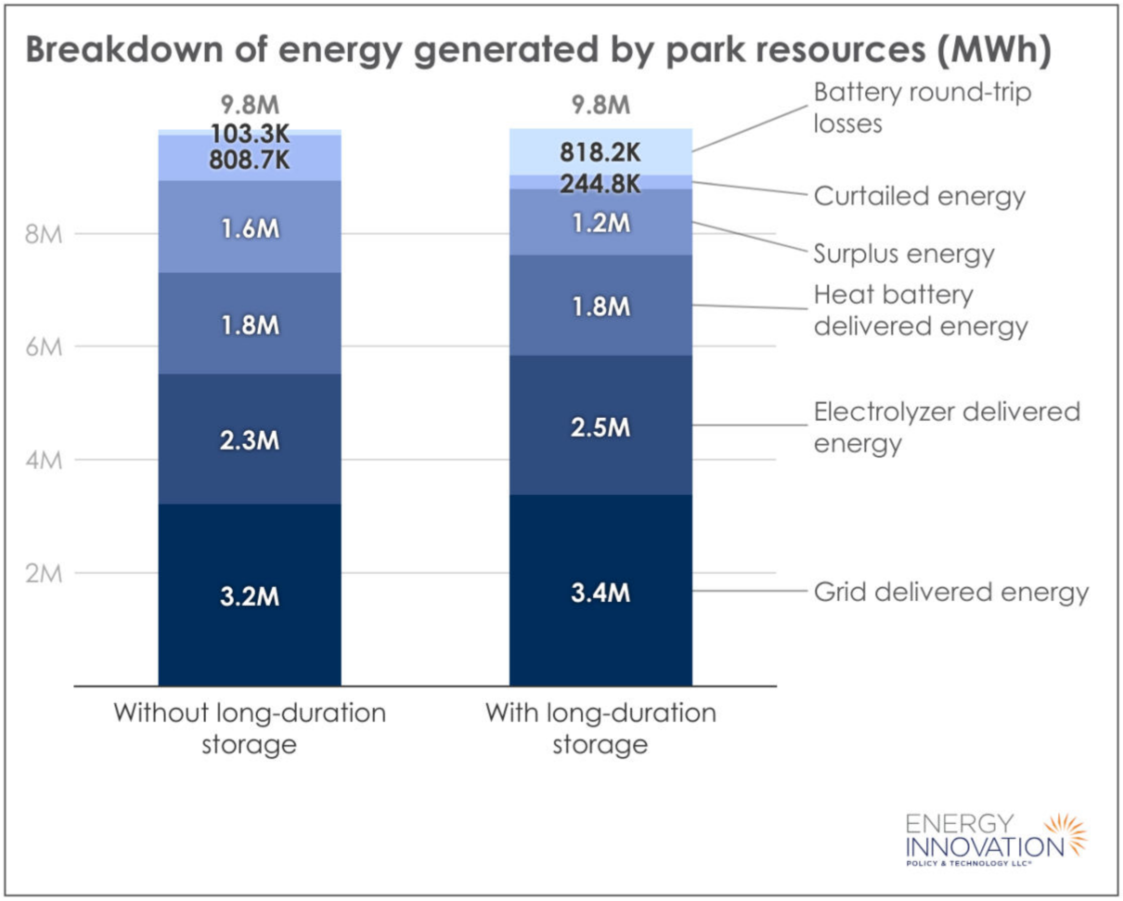
Key finding 1: The energy park is 99 percent reliable, and more than 40 percent of energy generated flows to Pueblo County

To start by explaining relevant terminology, energy that meets the target profile is considered "delivered" to the grid, 99 percent "reliable" means that 99 percent of the energy in the hourly target profile is delivered—; and we label any missing energy we label "unserved." The energy park also provides electricity to flexible industries (heat batteries and electrolyzers), and generates electricity that is surplus, curtailed, and lost in storage. Surplus energy is defined as energy generated above the target profile, but below a transmission export threshold of 800 MW, and curtailed energy is defined as energy generated above the 800 MW threshold.

The energy park's wind and solar resources generate more than 9,000,000 MWh of electricity in total over the course of the year. With no long-duration storage, we find that the first three energy park components alone can deliver more than 3,200,000 MWh to the grid, with only 5 percent unserved energy. Industries in Pueblo with flexible electricity consumption profiles receive even more energy than the grid, at 4,100,000 MWh.

Because so much energy can be stored in the thermal batteries for later use, surplus and curtailed energy are reduced when long-duration energy storage is included, while electricity delivered to the grid increases to 3,400,000 MWh. Delivered energy to Pueblo industries also increases to 4,300,000 MWh. More energy is lost in battery round-trip losses, but because stored energy is primarily energy that would be either surplus or curtailed, the portfolio's reliability improves. Unserved energy falls to approximately 1 percent, meaning that the energy park can match the target profile 99 percent of the time. This is much better than the unserved energy observed when comparing the existing Comanche Unit 3 to the target profile, which had 9 percent unserved energy in our historical data year. Note that our historical data year, 2023, was a relatively good year for Comanche Unit 3. In other years, its operation was much worse. For instance, in 2020 the unit only operated at a 3 percent capacity factor due to a prolonged outage.[13]

Figure 4. Breakdown of energy generated by energy park

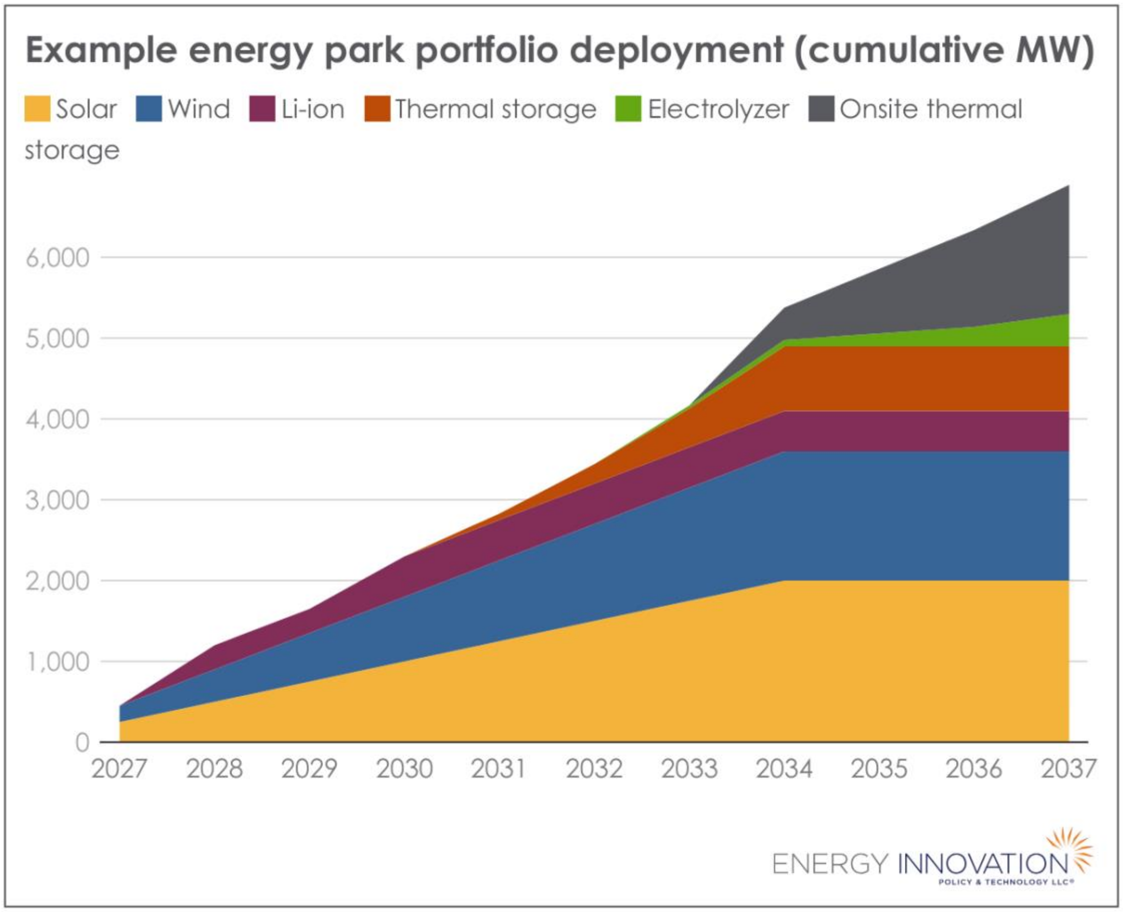


While this doesn't account for forced outages, the energy park is spread across several different wind, solar, battery, and thermal battery installations, and the likelihood of a forced outage across the entire energy park or even one category of energy park resources (i.e., wind or solar) is very low. Typical forced outage rates for a well-functioning coal, gas, or nuclear plant are 11.7 percent, 7.7 percent, and 2 percent, respectively,[14] indicating that barring a correlated outage across all energy park components, the energy park could be even more reliable than these resources traditionally considered "firm." To improve upon the reliability even further, measures such as a small backup boiler or additional batteries would suffice. With additional modeling described in Appendix B, we note that it may be possible to meet similar reliability values with primarily long-duration storage instead of including flexible loads. However, while such an energy park might hit operational milestones, it would be a lose-lose for Xcel customers and the Pueblo community due to increased costs for electricity ratepayers and reduced economic benefits for Pueblo.

Key finding 2: The energy park can generate more than $40 million in annual property tax revenue and 350 permanent jobs

To estimate the future property tax revenues generated by the energy park, including all four components, we create an example deployment that develops the portfolio of resources over the course of several years. This is not the only way the energy park could be developed, but we use this for illustrative purposes. For instance, in this example, thermal batteries and electrolyzers are largely deployed in the 2030s. However, with these technologies already in commercial development and use today, the deployment of these resources could be moved forward in time.

Figure 5. Example energy park development

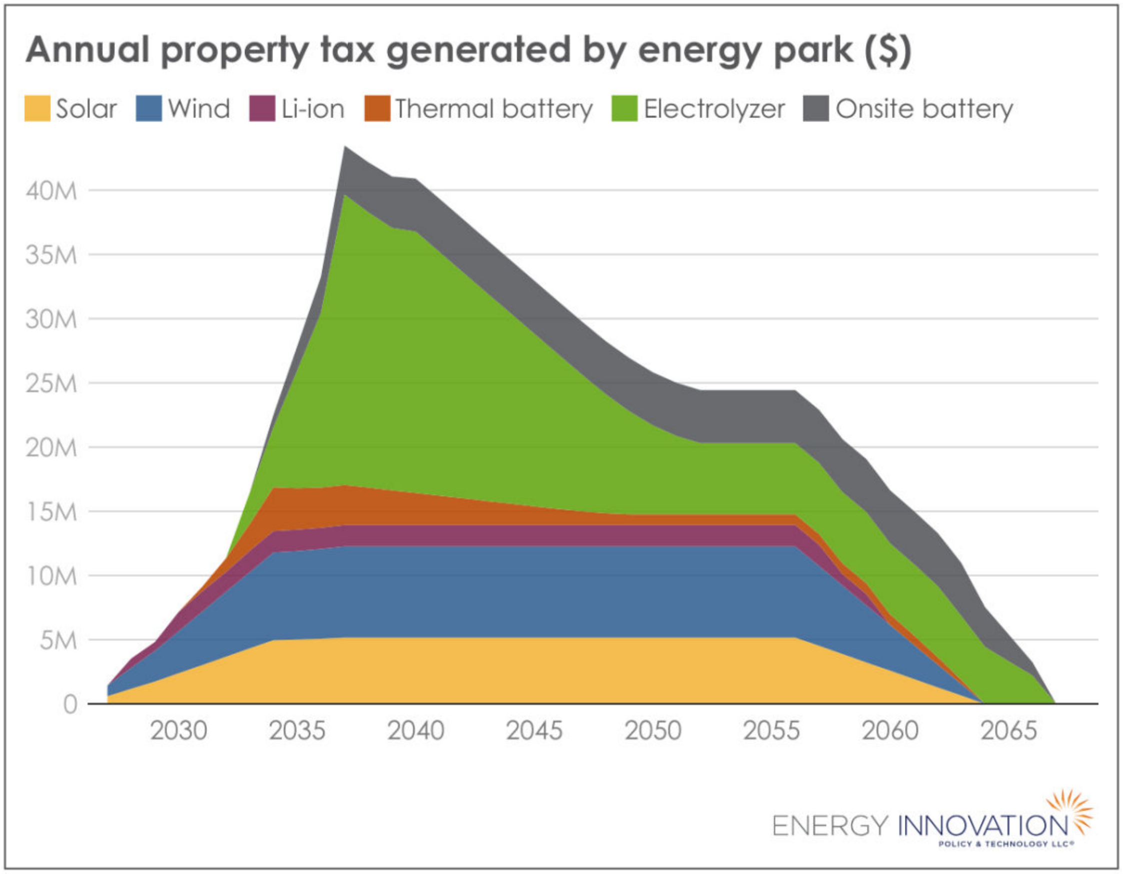


More than 350 permanent jobs could be generated by this portfolio, combined across all four components—significantly more than currently exist at Comanche Unit 3. Research from the National Renewable Energy Laboratory (NREL) shows estimates that approximately 15 permanent jobs are created at a 200 MW wind plant,[15] and five permanent jobs at a 200 MW solar plant.[16] Together, this would amount to 170 jobs across the installed capacity modeled in this paper. However, there is even higher job potential from flexible industrial technologies such as thermal batteries and hydrogen electrolyzers. Research from the Clean Air Task Force finds that up to 45 permanent jobs could be created per 100 MW of electrolyzer capacity installed, totaling 180 jobs for the 400 MW modeled. Permanent jobs include installers, maintenance, technicians, engineers, plant operators, and executives.[17]

As seen below, the largest portion of property tax revenue is generated by the electrolyzer due to the large amount of capital required to build this resource. But wind, solar, and short-duration storage alone still generate up to $13 million annually.

Property tax revenue is calculated using the income method for the clean energy generating resources (wind, solar, 4-hour battery storage, and on-site thermal batteries), according to the property tax regime for renewable resources in Colorado. We use the cost method to estimate the property tax revenue for the thermal batteries utilized for industrial heat and the electrolyzer since these resources do not provide electricity to the grid. The income method levels and spreads property tax across a roughly 30-year resource lifetime, while the cost method determines property tax according to the value of the resource, which depreciates over the course of the 30-year lifetime.[v] We do not account for potential periodic replacement of battery or electrolyzer components, which could increase property tax value for these resources. See Appendix C for details of property tax revenue calculations.

Figure 6. Annual property tax revenue generated by energy park example build-out



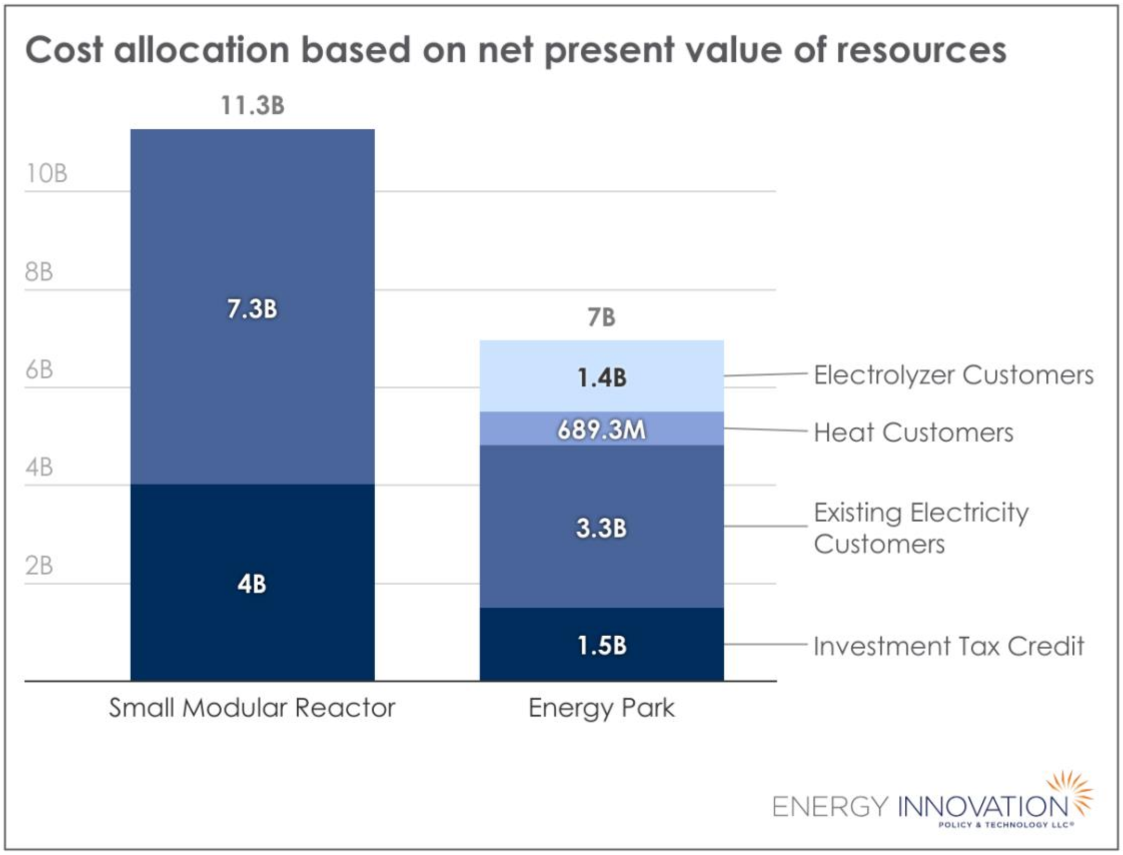
[v] This treatment of renewable energy for property tax assessment is different from other states' methods and reduces the property tax assessed for renewable energy resources.

Key finding 3: The energy park would cost Colorado electricity consumers at least 50 percent less than a comparable small modular reactor

Finally, we calculate how costs, based on net present value of the initial capital investment (discounted with a 40 percent investment tax credit) and operations and maintenance costs, would be allocated across both existing electricity ratepayers and new industrial customers. We compare this to a cost breakdown for a comparable clean firm resource such as a small modular nuclear reactor. For the small modular reactor, we include up-front capital investment (also discounted by a 40 percent investment tax credit), operations and maintenance costs, and fuel costs. For the energy park, we assume that all costs are paid for by sales to electricity, heat, and electrolyzer customers. The net present value of tariffs paid by the heat and electrolyzer customers is deducted from total costs after accounting for the investment tax credit, and the remaining amount is considered charged to electricity customers outside of the energy park, such as residential and commercial electricity customers. Cost assumptions and full methods are included in Appendix C. For the renewable energy park, about 47 percent of the costs, including operations and maintenance, fall to electricity customers outside of the energy park, totaling $3.3 billion. For the clean firm comparison resource64 percent of the costs, totaling $7.3 billion, are allocated to electricity customers outside of the energy park, while $4 billion is covered by the investment tax credit.[vi]

[vi] For the small modular reactor construction costs, we have based this calculation on the proposed but eventually cancelled NuScale 462 MW reactor project with Utah Associated Municipal Power Systems that had an estimated $9.3 billion in construction costs. The costs could be even higher considering that this reactor was never built, and prior to cancellation the projected construction cost had already increased significantly from the projected cost of $3 billion for the initially proposed 600 MW reactor.

Figure 7. Cost allocation of energy park costs compared to those for a small modular reactor



These figures can also be translated into levelized cost of energy estimates, with several caveats. First, there is significant uncertainty in underlying technology costs. Our technology costs are conservative; for example, we model higher renewable costs than those bid into Xcel/PSCo's most recent procurement process. Second, we make assumptions about institutional arrangements, such as assuming that heat is delivered from thermal batteries at a cost of $30/MWh. Third, uncertainty also remains regarding the price of surplus energy exported from the park. Here, we assume a price of $15/MWh. The energy park could build fewer new renewable resources and use existing surplus on the system, reducing the cost.

With these caveats in mind, we estimate the levelized cost of energy for the inflexible small modular reactor operating at 95 percent capacity factor to be $135/MWh, while the average cost of power provided from the energy park to the grid would be $56/MWh. If we discount the "surplus" fraction of power (to $15/MWh), the calculated levelized cost of energy is closer to $70/MWh for the “delivered” portion of power output matching the idealized profile.[vii]

ENERGY PARK BENEFITS

The advantages of the energy park span cost control, reduced pollution, economic development, and reliable electricity generation, with benefits spread among Pueblo County, Xcel and its electricity ratepayers, and the state of Colorado as a whole. For all stakeholders, a primary advantage of replacing the Comanche coal plant with an energy park is that diversification and the ability to incrementally build significantly lowers risk—in terms of both total investment cost and technology readiness. Instead of relying on a single technology or large project, the energy park would be developed in smaller individual steps that each add value, with the possibility of generating energy, jobs, and tax revenue even before Comanche Unit 3 closes in 2031.

BENEFITS FOR PUEBLO COUNTY

In Pueblo County, the advantages of developing a renewable energy park for the replacement of Comanche Unit 3 are primarily economic and health related. Health benefits include reduced air pollution from both the power plant and the industrial heat users that currently burn natural gas to generate process heat.

On the economic side, an energy park generates significant property tax revenue and jobs for the county. The energy park should be able to more than make up for the revenue lost from Comanche Unit 3, generating an average of $23.9 million annually, and up to $40 million. This revenue is just from the facilities built as part of the energy park and could be significantly higher when accounting for the attraction of additional industries looking for clean heat. The energy park also presents an attractive economic diversification strategy for Pueblo—one in which 25 percent of the county’s tax revenue does not depend on a single facility but instead stems from multiple smaller facilities. This would help avoid repeating the potential for a tax revenue cliff in the future. Furthermore, the energy generated by the energy park has significant potential to stay in Pueblo and provides both heat and power upscaled to drive new industry and jobs within the county, instead of exporting nearly all the electricity generated by a large power plant to electricity users throughout the state.

[vii] Levelized cost of energy is calculated by taking the annual revenue requirement and dividing it by the annual energy generation. For the small modular reactor, the annual revenue requirement based on an 8 percent capital recovery factor is $562 million, and the annual generation based on a 95 percent capacity factor is 4,161,100 MWh. For the energy park, we calculate the annual revenue requirement for electricity customers based on the 8 percent capital recovery factor as $255 million, and divide by the annual generation delivered to the grid both as a part of the target profile (3,374,000 MWh) and surplus (1,166,000 MWh).

BENEFITS FOR COLORADO ELECTRICITY RATEPAYERS

For Xcel's electricity customers, energy park benefits would include reduced cost of a power plant replacement compared to a single, large power plant, improved electric system reliability, and reduced exposure to fuel price volatility. In total, we estimate the net present value of investment in the energy park to be roughly $7 billion. But less than half of that, or $3.3 billion, would be paid by Xcel's electricity ratepayers, while the investment tax credit and electricity sales to heat and electrolyzer customers would cover the rest. This is significantly less than the cost that would be paid by electricity ratepayers in a simple one-for-one large power plant replacement. For example, the comparable 462 MW NuScale small modular nuclear project in Utah was cancelled after costs ballooned to $9.3 billion. If a similar project were initiated to replace the power from the Comanche plant, this could translate to more than $7.3 billion for electricity ratepayers even after applying the investment tax credit—more than double the ratepayers' cost for the energy park. Finally, an energy park, with its reliance on primarily wind and solar resources, would reduce fuel price volatility in Colorado electricity rates.[18]

BENEFITS FOR XCEL ENERGY

Xcel, the current primary owner of the Comanche power plant, would benefit through lower system costs, improved system function, progress toward the utility's own goal of 100 percent clean electricity by 2040, and a reduction in the just transition payments made to make up for property tax losses in Pueblo after the retirement of Comanche Unit 3. Xcel is on the hook for making up property tax from 2031 through 2040, so the sooner new resources come online and start providing tax revenue, the less Xcel will need to pay.

As of 2023, the Xcel rate base in Colorado was $14.9 billion,[19] which means that addition of a single plant at a capital cost of $6 billion to ratepayers could increase the rate base by over 30 percent. A cheaper option, like the energy park proposed here, would be more affordable. Xcel would also expand electricity sales at low cost because the energy park would use significant existing infrastructure such as substations and transmission lines.

The energy park would also help Xcel integrate additional planned renewable resources and new loads across the state. While the modeling in this paper only considers the energy park resource and not the entire Colorado electricity system, siting flexible industrial loads in southeast Colorado could enable additional utilization of excess wind and solar resources across the state during times of high output. This additional ability to integrate more clean resources could help Xcel meet its own goals instead of waiting for silver bullet resources that may only be ready in the late 2030s. As discussed in the modeling section of this paper, the energy park could also provide significantly higher reliability value compared to the existing Comanche Unit 3.

Finally, an energy park in Pueblo would help Xcel comply with Colorado's clean heat standard, as discussed in the next section. This would allow it to start remaking itself from a company that provides gas-for-heating with fuel cost as pass-through to one that uses capital and electricity for heating. This extends the "steel-for-fuel" strategy pioneered by former Xcel CEO Ben Fowke in 2017.[20]

BENEFITS FOR COLORADO STATE POLICY

Colorado has long been a leader in the clean energy transition—the state's first renewable portfolio standard was established by a ballot initiative more than 20 years ago, in 2004. This not only has helped the state accrue health benefits for its residents via reduced air pollution but also has made Colorado a leader in clean industries. For example, the CS Wind plant in Pueblo has been manufacturing wind turbine components since 2008 and is in the middle of a three-stage expansion plan that will make it the largest turbine manufacturer in the world.[21] Leading the country and world in development of a renewable energy park that helps simultaneously decarbonize electricity and industry can improve Colorado's position as an innovator and energy transition powerhouse while attracting new industries. For example, Colorado has shown interest in attracting a clean hydrogen industry to the state with its additional production tax credit for clean hydrogen production. The energy park could be the first step in bringing that industry to fruition in the state.

Colorado also needs to continue innovating given that the state's clean energy standard requires 100 percent retail electricity sales from clean sources by 2050. In 2021, the state also became the first to pass a clean heat standard, requiring a 22 percent reduction in emissions from heating compared to 2015 levels by 2030.[22] Roughly 29 percent of Xcel's heat emissions come from non-residential uses, such as industrial heat use. While the post-2030 interim target has not yet been set, it will likely require even steeper reductions in the 2030s, even as much low-hanging fruit like efficiency and residential heat pumps will have already been installed. The pioneering use of thermal batteries at the energy park to provide clean, steady heat to industries in Pueblo could help Xcel and Colorado continue to make progress on clean heat.

DEPLOYMENT BARRIERS AND POLICY CONSIDERATIONS

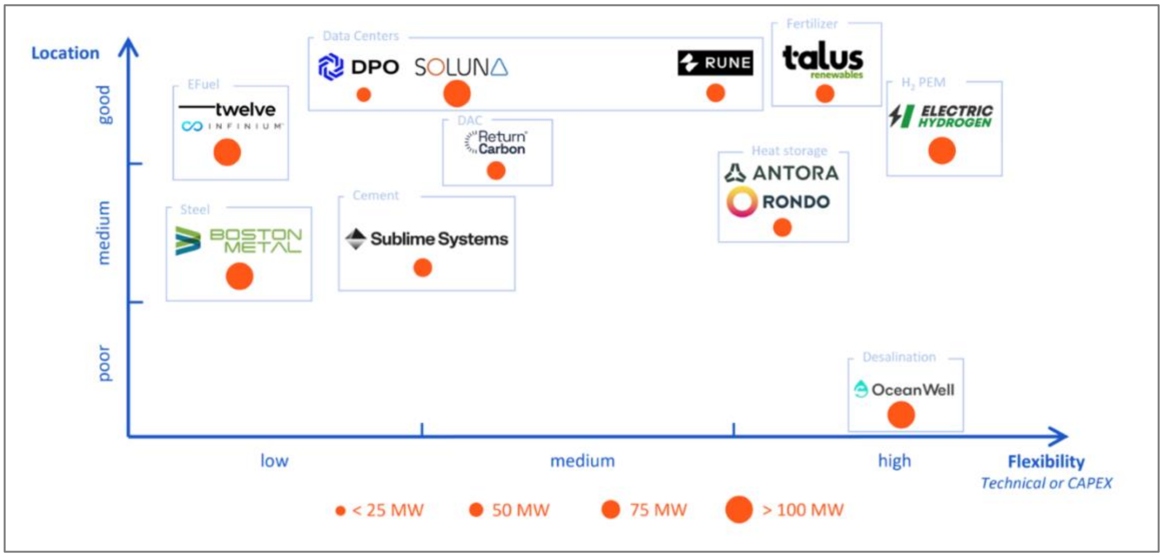
While a broad policy analysis is not within the scope of this paper, we offer for consideration an overview of a few key barriers to energy park deployment and solutions.

One of the primary barriers to deploying an energy park as it is described in this paper is attracting industrial customers to serve the crucial role of flexible load. To attract industries to the Pueblo energy park, Xcel will need to be able to incorporate flexible loads into its planning and procurement processes and offer competitive electricity rates for the power provided by the energy park to local flexible industrial consumers.

The energy park will also need a central coordinator to determine what flexible loads will be compatible with the energy park, as well as to orchestrate the components. This entity could be Xcel, but it could also be another central coordinator.

To incorporate flexible loads into the energy park, Xcel should begin to include flexible loads in its modeling, planning, and procurement processes. Xcel could follow the example set by EDF Renewables (EDFR), which is currently pioneering ways to incorporate flexible loads to upgrade its private projects by procuring flexible loads to co-locate and upgrading its generation resources in a commensurate way. To procure flexible loads, EDFR initiated a request for proposals in November 2024 that seeks behind-the-meter loads for co-location with 1.1 GW of renewable energy across nine projects in the U.S. and Australia. The renewable projects are already in operation but are generating excess power at certain times of the day and year. EDFR can offer benefits to behind-the-meter loads such as access to reduced energy prices.[23] Flexible loads identified by EDFR include those that we have modeled here, such as electrolytic hydrogen, green ammonia, and thermal batteries. Some additional loads that exhibit medium flexibility include data center companies like Rune, Soluna, and Verrus, as well as direct air capture of carbon dioxide.

Figure 8. Examples of flexible industrial loads from EDF Renewables



Source: https://www.edf-innovation-lab.com/flexible-load/

To enable Xcel to offer reduced electricity rates for flexible loads via a request for proposals, the Colorado Public Utilities Commission will need to create a process to determine whether these rates are just and reasonable. Therefore, the Commission should initiate proceedings such as requests for information to begin creating a framework for Colorado to price power for flexible loads. While some frameworks already exist, such as critical peak pricing that incentivizes industrial customers to reduce loads during times of high demand, the potential benefits of the energy park could be developed with other rate designs involving many more hours of reduced demand. For example, in the Electric Reliability Council of Texas market, “controllable load resources” can access wholesale electricity rates in exchange for responding to signals from the grid operator to curtail power or shift load to different times, primarily to provide ancillary services at this time. While this approach relies on access to wholesale electricity rates, Colorado could expand existing demand response programs to encompass controllable loads that could respond to capacity needs instead of just ancillary services.[24]

While technologies like thermal batteries and hydrogen electrolyzers are still new in terms of total number of projects, they are already in commercial deployment. New technologies can present risks in terms of understanding the ultimate reliability of the equipment or function in the broader system. However, the technologies modeled in this paper are already in commercial development stages. NREL indicates that the proton-exchange membrane electrolyzers that have maximum flexibility and are thus best suited for energy park integration are already in their final form and have been used in commercial operation in a wide range of conditions.[25,26] Thermal batteries are also at late stages of commercial development, with projects ranging from prototypes demonstrated in operational environments to those already used in commercial operation.[27] Funding for early commercial-scale deployments could help further de-risk this technology.

Finally, Pueblo County will need to work with developers of energy park resources to locate appropriate sites for the components. For example, electrolyzers could be sited at the PuebloPlex site, while 4-hour batteries could be sited at the Comanche site or at PuebloPlex, hybridized with some of the solar parks, or placed at various advantageous locations interconnected to Comanche. Coordination with other southeast Colorado communities on the potential for additional wind resources to be sited in regions of higher capacity factor will also help advance the energy park.

CONCLUSION

In this paper we have modeled how an energy park centered on the existing Comanche coal-fired power plant in Pueblo, Colorado, could provide replacement energy, capacity, jobs, and property tax, while stimulating new economic activity in Pueblo. Cheap, clean energy becomes the catalyst for a diversified economy. The example energy park, made up of solar, wind, short-duration storage, flexible industrial technologies, and long-duration storage, could generate electricity matching an idealized version of Comanche Unit 3’s output 99 percent of the time, and could generate up to $40 million in annual property tax and more than 350 high-quality permanent jobs in Pueblo. More than 40 percent of the energy generated would stay within Pueblo County, cleaning up existing industry and driving new investment.

This resource would cost Colorado ratepayers less than half the amount of a comparable 500 MW "clean firm" resource, such as a small modular nuclear reactor, and would help Colorado and Xcel progress toward goals for both the clean heat and clean electricity standards.

We are entering a new era of the clean electricity transition, one that requires new ways of thinking as growing electricity demand intersects with fast-approaching emissions reduction goals. Energy parks present an opportunity to create new sources of cheap, clean power for industry, while also supporting the electricity grid as an aggregate resource that can provide significant reliability benefit—on par with and in many ways better than fossil fuel generators.

The biggest challenge to developing an energy park as described in this paper is coordination between electric utilities and flexible loads—the utility needs to be able to rely on the flexible load behaving as expected in orchestration with other resources on the grid, and the flexible load needs to have certainty on power availability and cost.

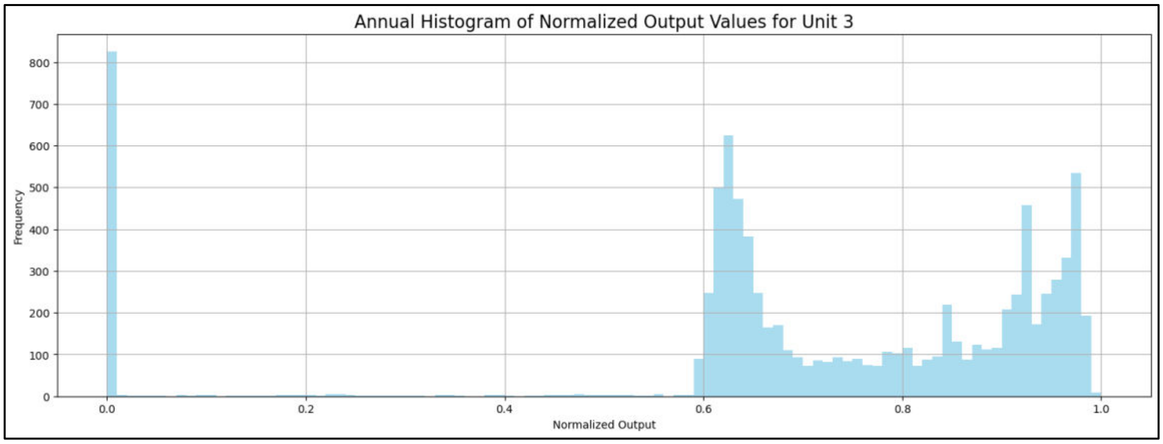
Yet with such strong benefits to electricity customers, utilities, host communities, and the flexible loads, the upside to engaging these entities together is too high to ignore. There are already existing examples of incorporating flexible loads into planning practices, and Colorado has an opportunity to build on these and pioneer this arrangement while continuing to push the envelope on a clean and affordable future for all.

TECHNICAL APPENDIX

APPENDIX A: CREATING AN IDEALIZED COMANCHE UNIT 3 "TARGET" PROFILE

To use Comanche Unit 3 energy generation profile in 2023 as a good target profile for an energy park, we needed an idealized version of the unit's behavior, that we can use to optimize the energy park dispatch around. We downloaded the U.S. Environmental Protection Agency data for the gross electric output from Unit 3 (gross load is network load and station load combined, a conservative estimate for actual exports to the grid) and then normalized to maximum output (this should the model mostly indifferent to gross vs. net output). The following histogram clearly shows the initial issue with using Unit 3 as a model: more than 9 percent of the time, Unit 3 was at zero output. Individual event data included in this appendix (along with other contextual data we reviewed) indicates that these were most likely unforced outages (a continuation of historical problems with the unit).[28]

Figure A1. Histogram of Comanche Unit 3 output in 2023

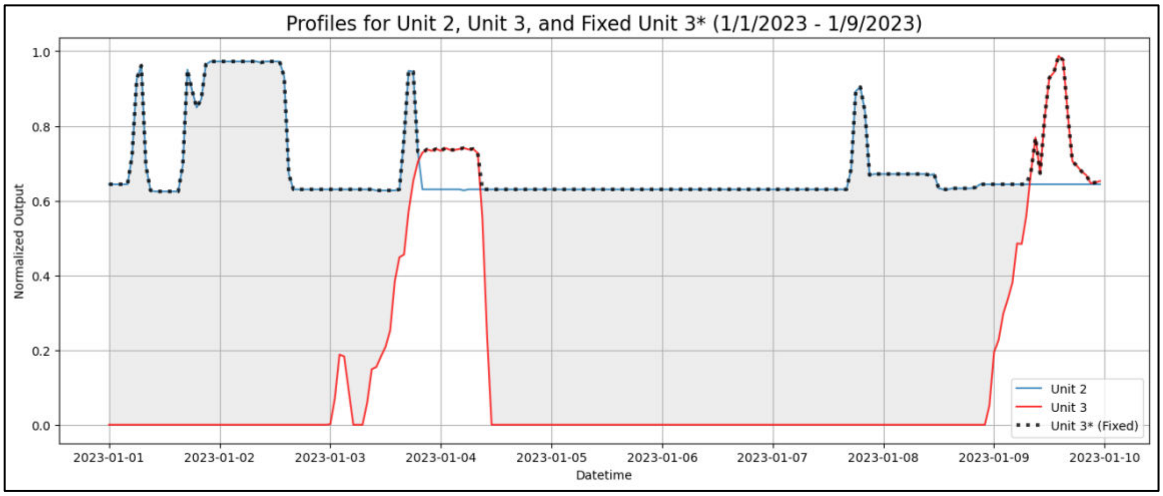


To better identify an idealized version of Unit 3 (we call it Unit3*), we selected the eight main periods of significant drop in output for Unit 3 and used some combination of extrapolation from surrounding Unit 3 output and how Unit 2 was behaving at the same time to create a more idealized output, Unit 3*, that would be a better reference target for our analysis. We don't need a "perfect" proxy, just something that is a suitable model to target.

Period 1 (Jan. 1 to Jan. 9, 2023):

In this period, Unit 3 was clearly struggling to come back on during the night of January 4 to 5. The spike in output was likely not peaking behavior because the whole system needed energy throughout this week (low wind and solar) and peak demand does not occur in the middle of the night. Our strategy for this interval was to set Unit 3* normalized output (0-100 percent) to the maximum value between Unit 2 and Unit 3.

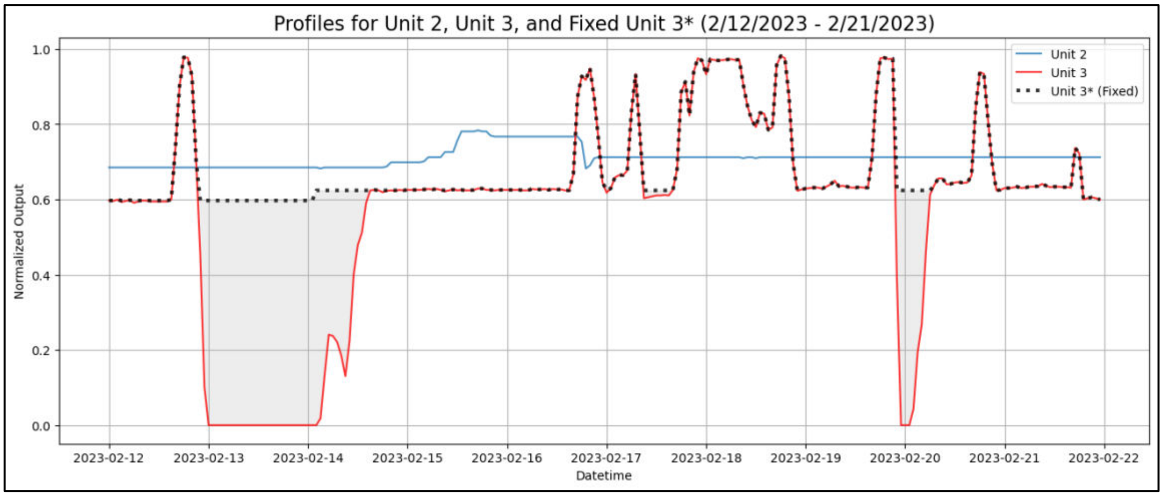
Figure A2. Period 1 profile comparison



Period 2 (Feb. 12 to Feb. 21, 2023):

Here, Unit 3 is basically sitting at some base level of operation (~60 percent) and then peaking on demand. Our strategy for this interval was to fill in the outage "potholes" with minimum output. Since this minimum changed a bit from February 13 to 15, we had to step up a bit midway.

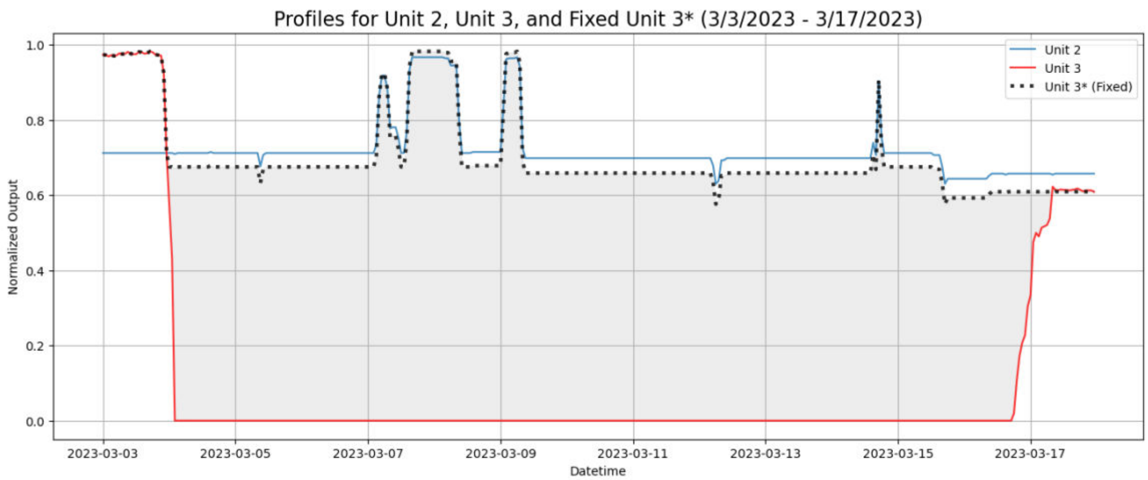
Figure A3. Period 2 profile comparison



Period 3 (March 3 to March 17, 2023):

Here, we assumed that Unit 2 had to do some peaking work instead of Unit 3, so instead of filling the outage pothole with a flat minimum, we added a few peaking spikes modeled on Unit 2. We also did some rescaling to match Unit 3 at each end.

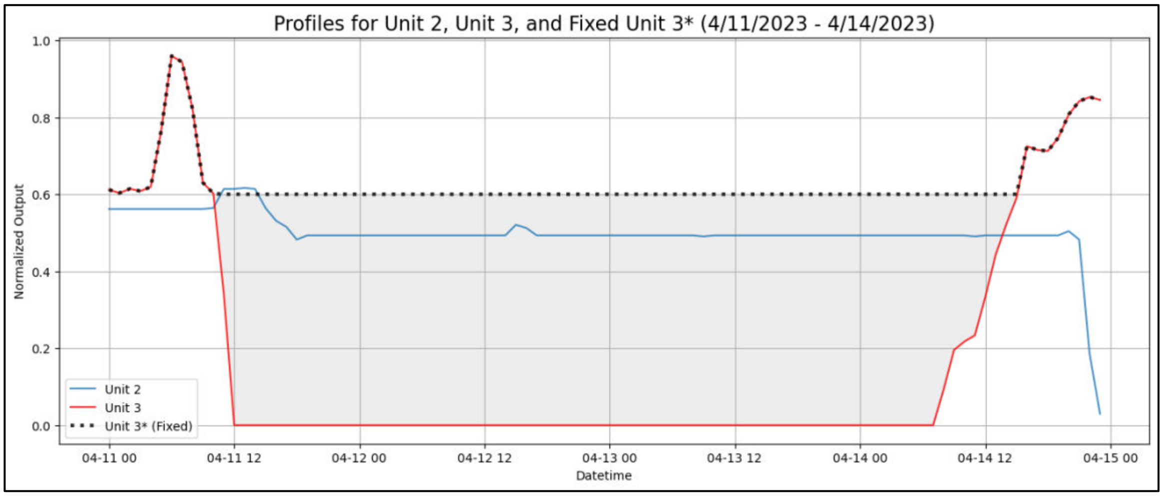
Figure A4. Period 3 profile comparison



Period 4 (April 11 to April 14, 2023):

It is possible that Unit 3 was down on purpose during a period of high renewable output on the system, with Unit 2 carrying some basic load and reliability service. However, given Unit 3's spotty performance record, we assumed that ideally it would have been sitting at P_{min}, in this case roughly 60 percent of maximum output.

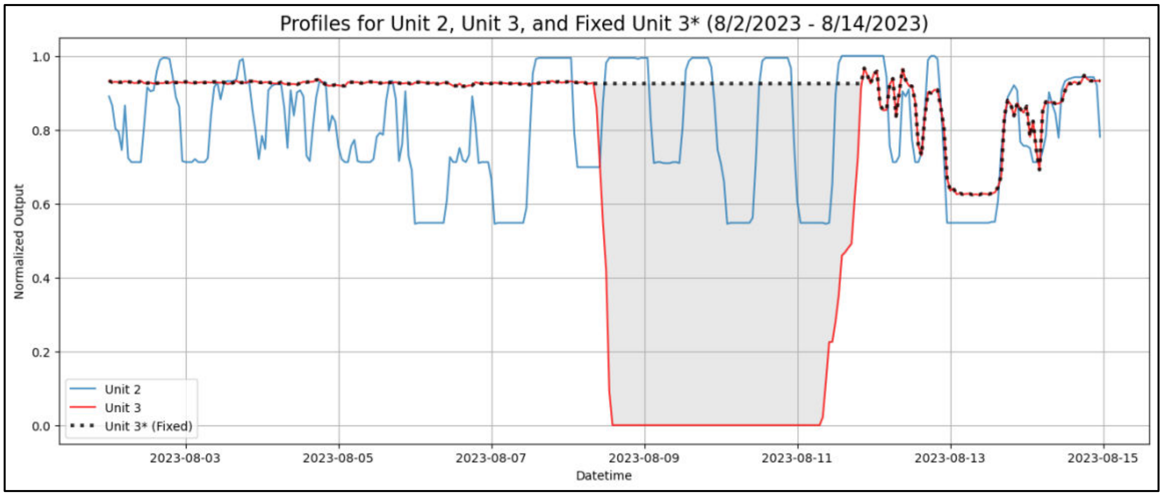
Figure A5. Period 4 profile comparison



Period 5 (Aug. 2 to Aug. 15, 2023):

Here, we noticed that Unit 3 entered the period before the pothole at a high-capacity factor while Unit 2 was cycling. We assumed that Unit 3* was not required to cycle until August 12. The pothole below overlaps with a big 2,000 MW+ "peak to trough" wind production spike, so perhaps the downtime was intentional. On the other hand, for a similar spike on the August 6, Unit 3 did not change its output. Unable to second-guess the grid operator, we assumed a flat high-profile continuation for Unit 3* across the sudden Unit 3 output drop.

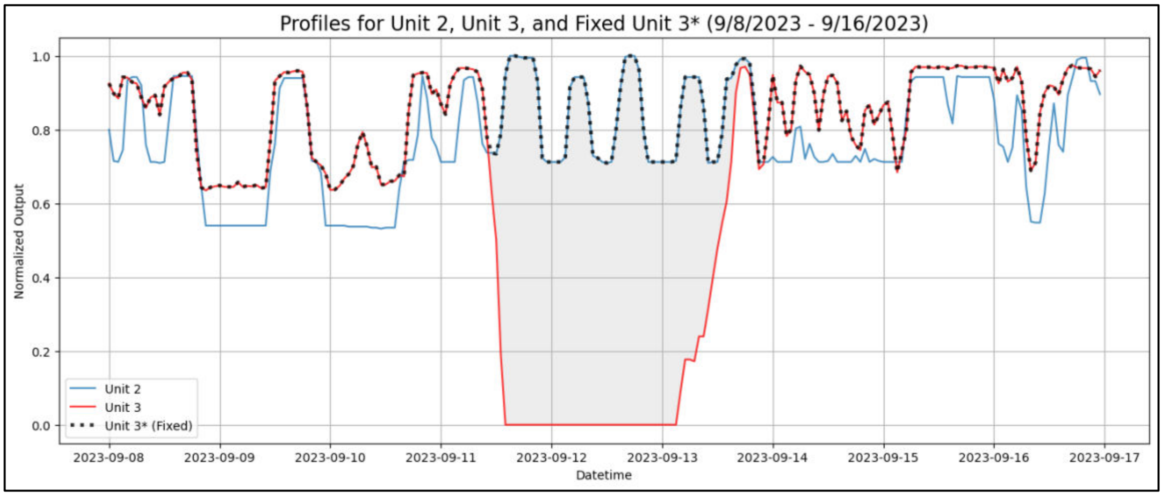
Figure A6. Period 5 profile comparison



Period 6 (Sept. 8 to Sept. 16, 2023):

Here, we see both Unit 2 and Unit 3 cycling before and after the September 11 to 13 pothole. Our strategy for this period for Unit 3* is to use the maximum of Unit 2 and Unit 3 normalized outputs to keep up the cycling behavior. It seems unlikely this outage was intentional, as big spikes in system variable renewable (wind) output occurred mostly overnight on September 9 and 10 (where we see some cycling down but no outright switching off).

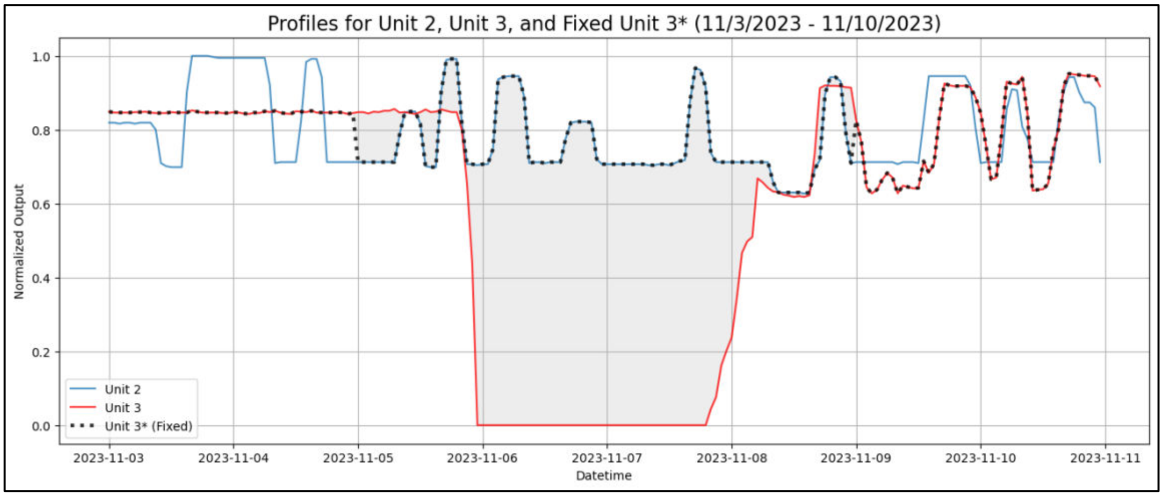
Figure A7. Period 6 profile comparison



Period 7 (Nov. 3 to Nov. 10, 2023):

Again, we see Unit 2 and Unit 3 both cycling before and after the November 6 to 8 pothole, so our strategy is to match Unit 3* to Unit 2 from November 5 hour 21 to November 8 hour 14 to ensure consistency across what would otherwise be an outage.

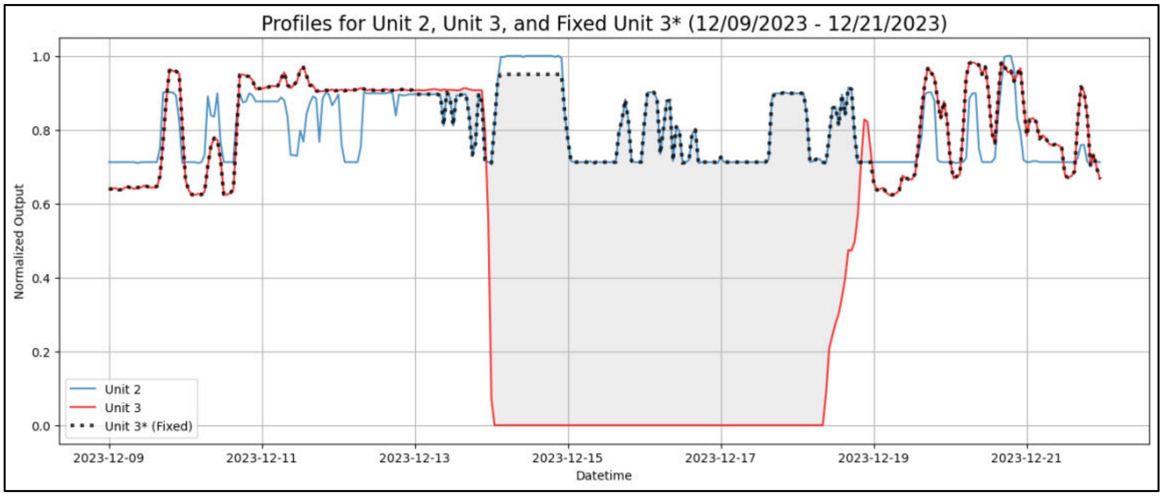
Figure A8. Period 7 profile comparison



Period 8 (Dec. 9 to Dec. 21, 2023):

Once again, we see complicated cycling behavior for both units before and after the December 13 to 18 pothole. Our strategy is to have Unit 3* match Unit from December 13 hour 22 to December 18 hour 20, all the while ensuring Unit 3* does not exceed 95 percent capacity factor (the maximum output we observe from Unit 3 in surrounding hours) during this interval.

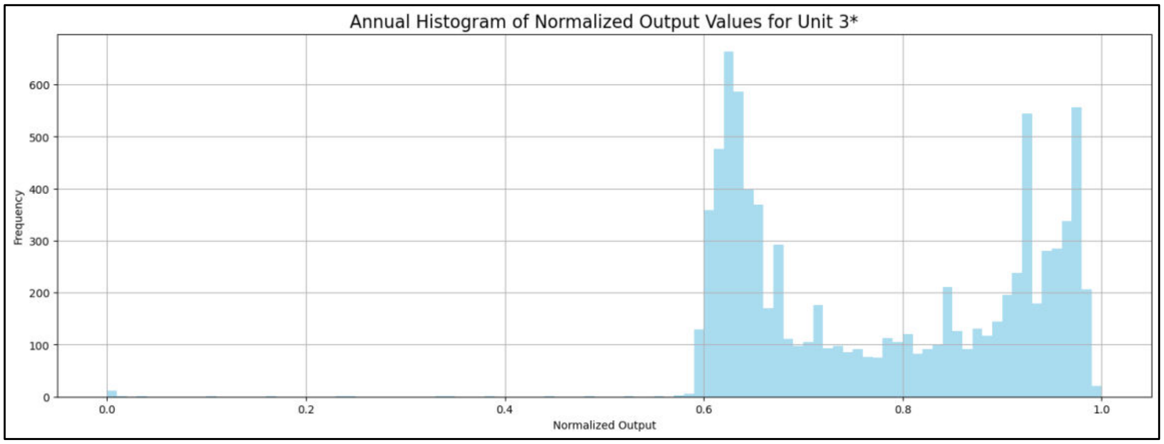
Figure A9. Period 8 profile comparison



Final profile for Unit 3*:

After "fixing" Unit 3, we obtain a profile for a more dependable Unit 3* throughout 2023 that we can use as a target to which our energy park can aspire. The fix results in the following improved output histogram:

Figure A10. Final output histogram for Unit 3*



APPENDIX B: METHODS AND MODELING

Here, we provide additional details on our model outputs for the energy park detailed in the main text of the report. To better illustrate the function of each of the four components of the energy park, we present our modeling in a layered incremental approach. This should not be interpreted as advocating for an actual build-out in this order. The energy park can be built gradually with each of the components coming online in more granular amounts. Objectives around firming output, minimizing surplus and waste, controlling costs, and the like will be met in proportion to how well balanced the amount of each component appears in each iteration of the build-out.

Apart from some crude initial optimization of the solar and wind portfolio, our model portfolio is not optimized around the initial capacity for the four components. We did use an optimizer to create hourly dispatch profiles for different illustrative combinations below. This optimizer considered opportunity costs that prioritize (in order) meeting the target profile, providing steady 24/7 clean electrified heat, running an electrolyzer, and selling surplus energy generated above the target output to the grid (within transmission limits).

Below we detail the quantities and model characteristics of our components, along with some illustrative model runs that showcase what each component principally provides the energy park. This is by no means an optimized build-out for the energy park, but as the annual metrics show, it already provides compelling results.

Run 1: Solar and wind with overproduction

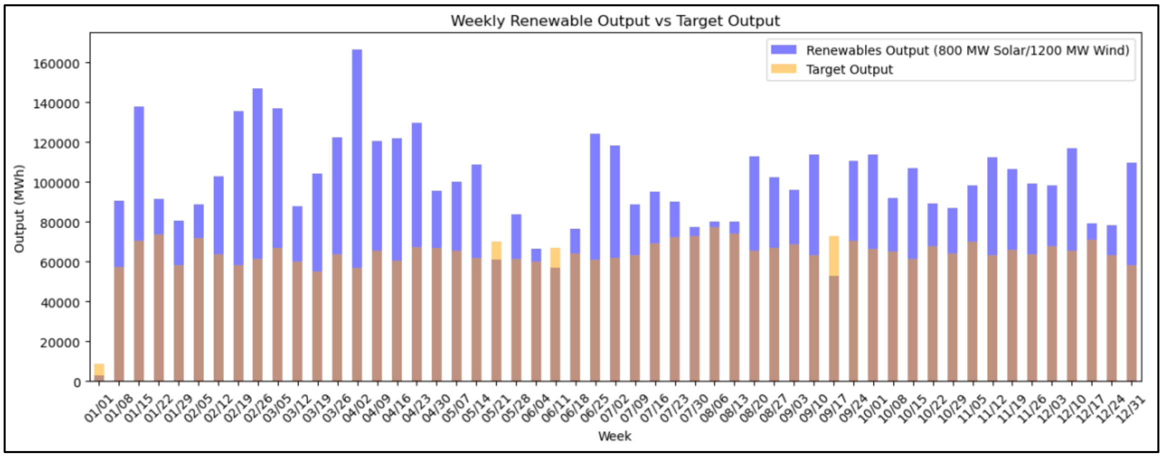
We developed a model profile for a local solar resource near the city of Pueblo and a local wind resource in one of the windier parts of Pueblo County that could be interconnected directly into the energy park. The solar resource in Pueblo is quite good. The one-axis-tracking solar farm with a 1.3 DC-to-AC inverter loading ratio we modeled in Renewables.ninja has a 34.7 percent capacity factor. Wind in Pueblo County is not as attractive: the Renewables.ninja modeled wind resource had only a 26.8 percent capacity factor, but the production profile is more even seasonally and throughout the day when compared to solar and is thus a good complement to the solar profile.

Any viable energy park requires a portfolio of wind and solar resources that produces more annual energy than the target profile along with sufficient energy to satisfy the flexible loads and cover round-trip battery losses. This means that the combined portfolio output will frequently exceed the 300-500 MW output associated with the target profile. Beyond covering demand from flexible loads, we assume some fraction of the extra production over and above the target is wasted and never exported to the grid. This energy is considered “curtailed.” We also assume that another fraction can still be exported to the grid in a way that is manageable for the grid operator, considered to be “surplus” energy generated over the target profile. Because the existing Comanche Unit 3 capacity is 857 MW, we constrained ourselves to 800 MW as the maximum transmission threshold (labeled “max output” below) for exports so that our model would force some curtailment. To recap, we model any energy surplus generated between target and 800 MW as “surplus,” while energy generated over the maximum threshold of 800 MW is considered “curtailed.”

Throughout the runs, the main goal for each modeling exercise is to meet the target profile given a set of resources. Our optimizer tries to minimize any shortfall relative to target first, with a strong opportunity cost set at $10,000 per unserved target MWh.

As mentioned earlier, we did not try to optimize both resource mix amounts and hourly behavior simultaneously. This allowed us to reduce computing time and to match ambitious but realistic aspirations for flexible loads and long-duration storage. However, we still started with a roughly optimized base wind/solar portfolio and then experimented with different amounts of incremental capacity for that component and the other three. A more thorough analysis could perhaps achieve even better results by co-optimizing the capacity expansion of each component (including higher-capacity-factor out-of-county wind and available surpluses on the Xcel/PSCo system).

Figure B1. Comparison of weekly renewable portfolio output with target output

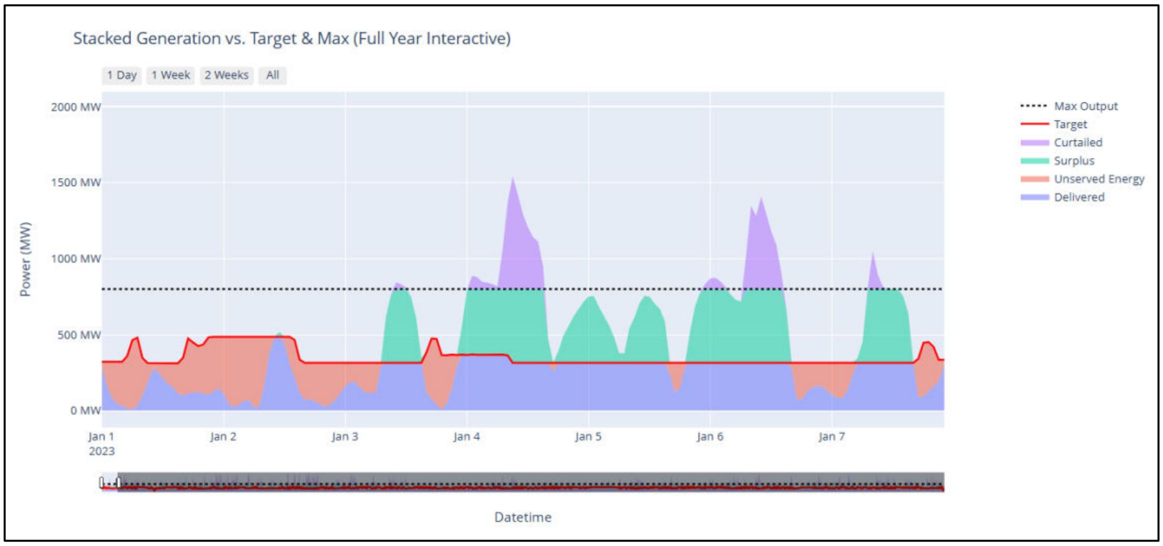


Data sources: Energy Innovation modeling, Renewables.ninja, EPA Clean Air Markets Program data

For our initial base renewable portfolio, we simply optimized wind and solar capacity by looking at aggregate weekly renewable output against weekly target output. We optimized around minimizing weekly shortfalls under an annual curtailment maximum of 15 percent without considering the relative cost of wind vs. solar capacity. The curtailment cap was necessary because building more wind and solar makes it easier to match the target profile but also leads to more wasteful curtailment and surplus. Our initial optimization led to an initial base renewable portfolio of 800 MW solar and 1,200 MW wind, which generates 5,247,532 MWh annually (compared to 3,094,295 MWh for the target profile).

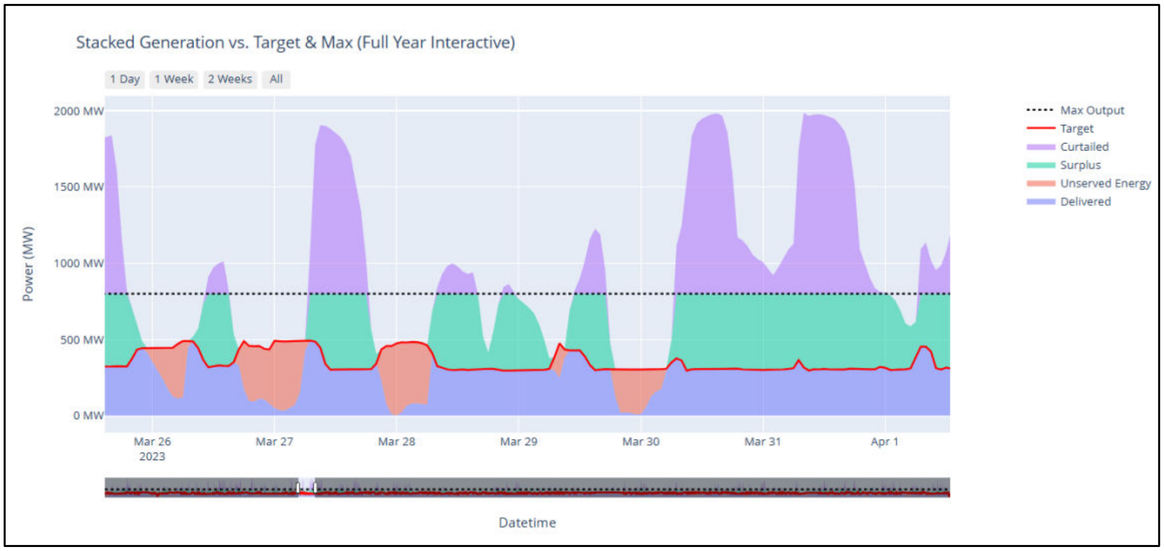
As seen in Figure B1, in all but four weeks of the modeled year the base portfolio matches or exceeds the target. However, when looking at the results at an hourly level (without any of the three other components), the matching challenge is more extensive. To illustrate this underlying challenge, we look at two different one-week windows in our first run with just a base portfolio's output data: the first week of the year and the early spring week following March 26.

Figure B2. First week of the year resource dispatch for Run 1



In the first week of the year, there are periods of time when energy production by renewables cannot match the target profile as both solar and wind output are low, leading to unserved energy (13,741 MWh in the first 60 hours or 2.5 days before the first surplus peak). Yet there is also some curtailment during peak solar hours later in the week. In the early spring week following March 26, production gaps compared to the target remain, but more importantly, overproduction leading to curtailment is massive, with up to 1,200 MW of curtailment.

Figure B3. Week following March 26 resource dispatch for Run 1



Given the profile of renewable energy production throughout these weeks, even doubling the renewable portfolio size would do little to improve the gap in production at the beginning of the year but would significantly exacerbate overproduction in early spring. The renewables-only base portfolio has both a "gap" problem and an "overproduction" problem. At this stage, the energy park achieves 76 percent reliability on the target portfolio while almost half the renewable portfolio production is either surplus or curtailed.

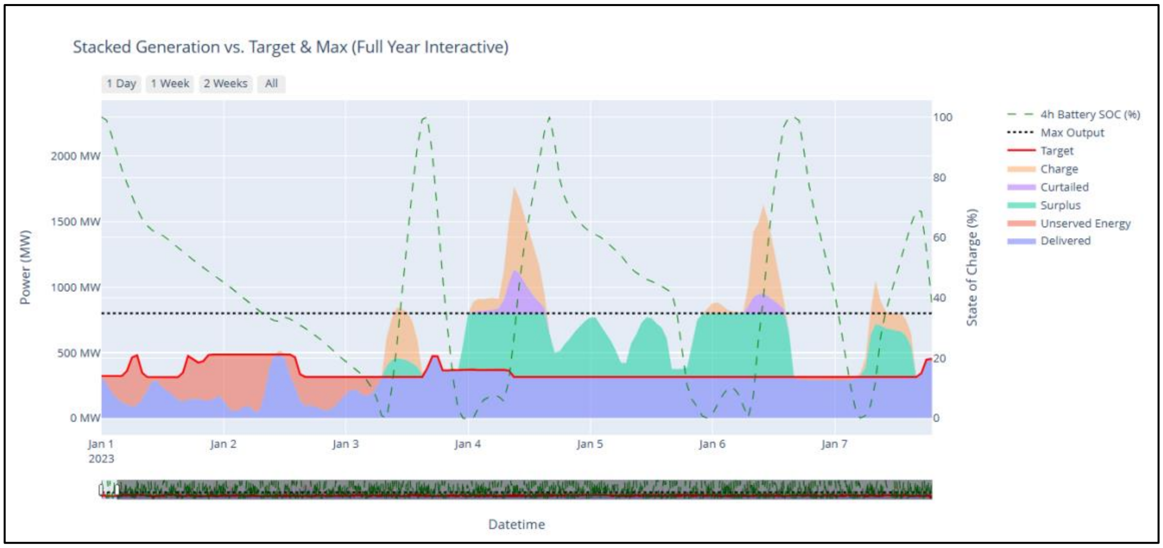
> Run 1 Optimization Summary:
> *Total RE Produced (MWh): 5,247,532*
> *Total Unserved Energy (MWh): 815,431*
> *Total Delivered Energy (MWh): 2,597,151*
> *Total Curtailed Energy (MWh): 787,209*
> *Total Surplus Energy (MWh): 1,863,172*
> *Unserved Energy (% of Annual Target):* ***23.89****%*
> *Delivered (% of Total RE): 49.49%*
> *Curtailed (% of Total RE): 15.00%*
> *Surplus (% of Total RE): 35.51%*

Run 2: Short-duration 4-hour lithium-ion batteries

Our final vision for the energy park includes 500 MW/2,000 MWh lithium-ion batteries with 90 percent round-trip efficiency. We chose a power rating of 500 MW to guarantee our energy park always had the instantaneous power required to meet the target if energy was available. We did not optimize the duration for the battery (i.e., 2 hours or 8 hours), as 4-hour storage is a common configuration for this technology today and we achieved good results with 4 hours. Further capacity optimization could find that different durations achieve equal or better results at lower cost. Furthermore, in a practical build-out, battery capacity is likely to be spread around multiple locations within the energy park (for example, at the Comanche site, at internal transmission pinch points, at the individual solar parks for DC-coupling, at some of the flexible loads for better buffering and system security), and that spreading might lead to more total power capacity.

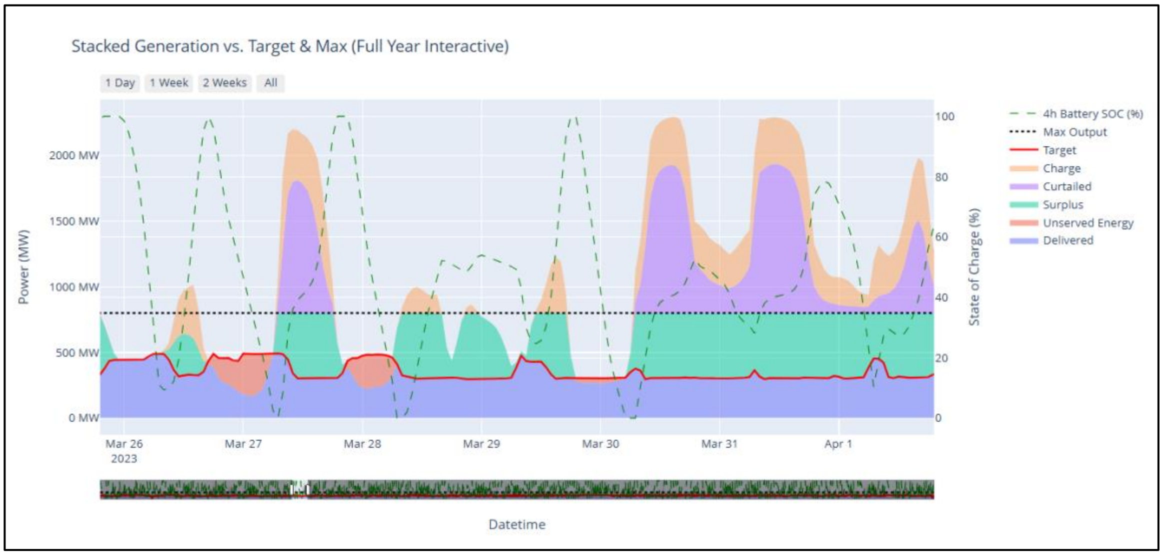
In the second model run below, we have combined the base portfolio of 1,200 MW of wind and 800 MW of solar with the 500 MW battery. This model run illustrates how the battery absorbs some potential surplus and curtailed energy and provides energy back during times of low renewable output. Because the run only covers a single year, we need a heuristic for the initial state of charge. For our modeling, we have the solver optimize with the assumption that the starting battery state of charge on January 1 matches that of December 31, with the idea that conditions in late 2023 are a proxy for conditions in late 2022 as far as fixing the state of charge. To ensure the battery prioritized surplus over curtailment, we added a bonus of $15/MWh for surplus power to our solver's objective function.

Figure B4. First week of the year resource dispatch for Run 2



In the first week of the year for this second run (base portfolio plus short-term battery), even though the battery starts the year almost completely charged, the 2,000 MWh of stored energy is not quite enough to make it through the low wind and solar production, and 11,700 MWh remain unserved compared to the target profile. The battery significantly reduces the curtailment later in the week, however, by storing it until it can be exported as delivered energy or surplus. It also eliminates any further gaps.

Figure B5. Week following March 26 resource dispatch for Run 2



In the early spring week, unserved energy is reduced, but there are still hours when more than an instantaneous 1,100 MW of renewable energy production is wasted to curtailment—the battery just can't charge fast enough to soak up the excess. Still, this run already shows a marked improvement in the yearly totals. The modeled energy park achieves almost 90 percent reliability (better than the actual Comanche Unit 3 coal plant) and overproduction is significantly reduced. Curtailment is now in single digits, although when battery losses are included, 10.21 percent of the initial renewable energy produced is wasted.

<u>Run 2 Optimization Summary:</u>
Total RE Produced (MWh): 5,247,532
Total Unserved Energy (MWh): 343,622
Total Delivered Energy (MWh): 3,068,961
Total Curtailed Energy (MWh): 435,329
Total Surplus Energy (MWh): 1,648,770
Total Charging Energy (MWh): 948,996
Unserved Energy (% of Annual Target): ***10.07%***
Battery Losses (% of Total RE): 1.81%
Delivered (% of Total RE): 58.48%
Curtailed (% of Total RE): 8.30%
Surplus (% of Total RE): 31.42%

Run 3: Adding flexible loads (thermal batteries and electrolyzers)

One way to reduce the gap between renewable energy production and the target profile is by adding more available renewable generation, but this inevitably creates more surplus and curtailment. Fortunately, we can reduce this overproduction by adding flexible loads. Our final energy park contains 10 thermal batteries, based on the Rondo RHB 300, for 800 MW input capacity and 3,600 MWh of thermal energy storage with 200 MW of steady-state thermal output and 400 MW of electrolyzer capacity.

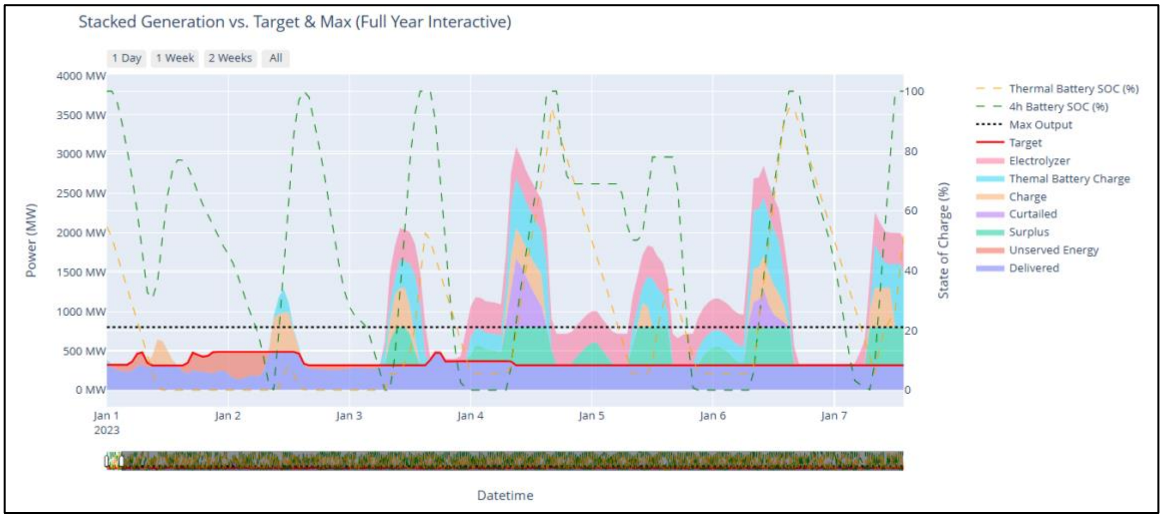
We made our choice for flexible load capacity based on considerations of Pueblo businesses and projects underway. We considered some of the existing industrial thermal loads in Pueblo that could be converted to clean electrified heat but assumed that some new industries might be interested in moving inside the energy park boundaries to benefit from cheap clean heat. The electrolyzer sizing was based on the Project Meitner sustainable fuels facility under consideration by Intersect Power in the Texas panhandle, as mentioned in the main text. These seemed like feasible amounts, and large enough to get a sense of the impact of flexible loads on the overall energy park.

Of course, new loads need more supply, so we also estimated and tested a few extra runs for sensitivity not shown here, ultimately adding an extra 1,200 MW of solar and 400 MW of wind for the energy park portfolio, for a total of 2,000 MW of solar and 1,600 MW of wind. We added more solar than wind at this stage because it is easier to build inside the energy park and we wanted to avoid potential interconnection limits in importing out-of-county wind if some was substituted for in-county wind.

To appropriately place electrified heat in the priority order for the optimizer, baseload thermal output from the thermal batteries is valued at $500/MWh in the objective function. We don't expect the project to sell power to heat customers at that rate, because the input of the battery operates at down to roughly 25 percent availability relative to input capacity (not unsurprising for a battery with a 4-to-1 ratio between maximum input power and maximum output power). However, we still want the algorithm to prioritize steady thermal service from the battery. This is accomplished by using an intermediate value between the high premium put on the reliability in matching the target profile and the low value of power fed to surplus and the flexible electrolyzer. We optimized around an electrolyzer opportunity cost at $40/MWh after some discussion with commercial actors, but this could easily +/- $10/MWh after negotiations between the utility and the flexible consumer. In any case, these are not actual prices that will be compared with cost of capital (we don't co-optimize with capacity expansion); they are simply meant to create reasonable priority for the optimizer when coordinating resources.

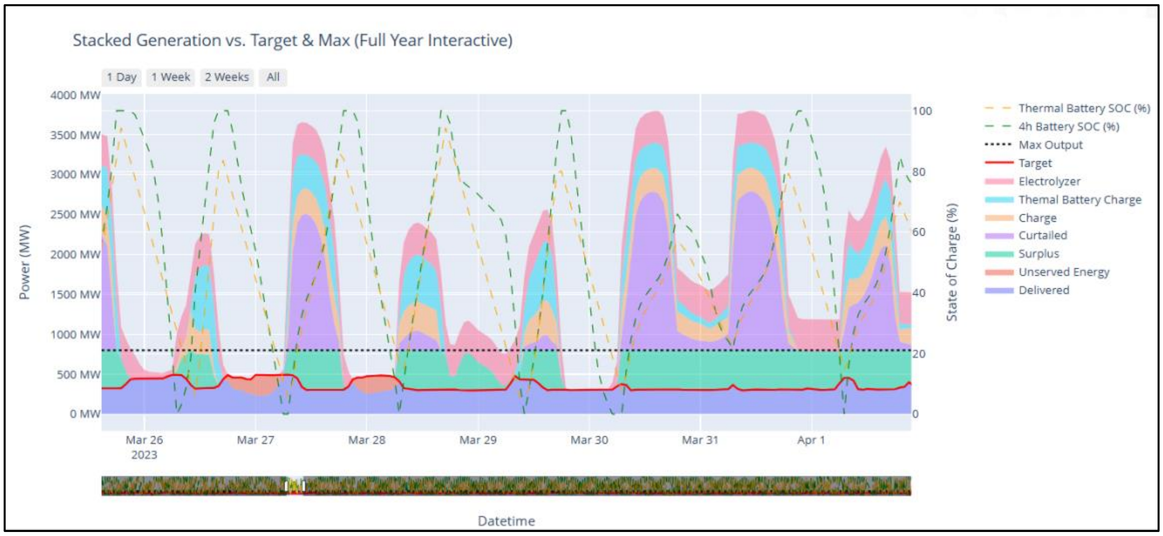
In our third run, the combination of the first three components of renewable energy, short-duration batteries, and flexible loads begins to demonstrate both the catalytic effects of flexible loads on the performance of the energy park and the advantages of co-locating most of the resources behind the main point of interconnection to the bulk power grid.

Figure B6. First week of the year resource dispatch for Run 3



In the first three days of the modeled year, due to low wind and solar output, all the additional generation can help support production toward the target profile, and no generation flows to the thermal batteries or the electrolyzer. The total deficit against target in the first three days is therefore more than halved, but despite an initially full 4-hour battery the deficit still reaches 5,771 MWh. Meanwhile, the thermal battery also hits zero state of charge, indicating that some of the thermal loads will need to use backup heat supply. Later in the week, we see total output over 3,000 MW but curtailment is kept under 800 MW because the flexible loads and batteries can absorb extra power.

Figure B7. Week following March 26 resource dispatch for Run 3



In the spring week, the impact of disproportionally adding solar to the portfolio is clear, as the mid-day peaks lead to some extreme overproduction relative to the 500 MW scale of our target profile. Even on the days with the highest solar generation, however, batteries and electrolyzers manage to shave off 30-40 percent of the curtailment. In aggregate over the year, there is a net positive effect from the generation plus flexible load enhancement to the base renewable portfolio with short-duration battery. The energy park achieves almost 94 percent reliability against the target profile, an impressive result. This run

<u>Run 3 Optimization Summary:</u>
Total RE Produced (MWh): 9,834,720
Total Unserved Energy (MWh): 192,842
Total Delivered Energy (MWh): 3,219,741
Total Electrolyzer Delivered Energy (MWh): 2,289,894
Total Electricity Delivered to RHB (MWh): 1,802,722
Total Curtailed Energy (MWh): 808,694
Total Surplus Energy (MWh): 1,610,503
Total Charging Energy (MWh): 1,036,673
Total On-site Heat Battery Charging Energy (MWH): 1,802,722
Unserved Energy (% of Annual Target): 5.65%
Battery Losses (% of Total RE): 1.05%
RHB Losses (% of Total RE): 0.98%
RHB Thermal Delivery (% of Total RE): 17.41%
Delivered (% of Total RE): 32.74%
Electrolyzer (% of Total RE): 23.28%
Curtailed (% of Total RE): 8.22%
Surplus (percent of Total RE): 16.38percent
RHB Availability: 97.44percent

provides this while reducing the percentage of energy generated over the target profile (losses + surplus + curtailment) from 41 percent down to 27 percent, mostly by reducing the surplus percentage (losses and curtailment still combine to around 10 percent).

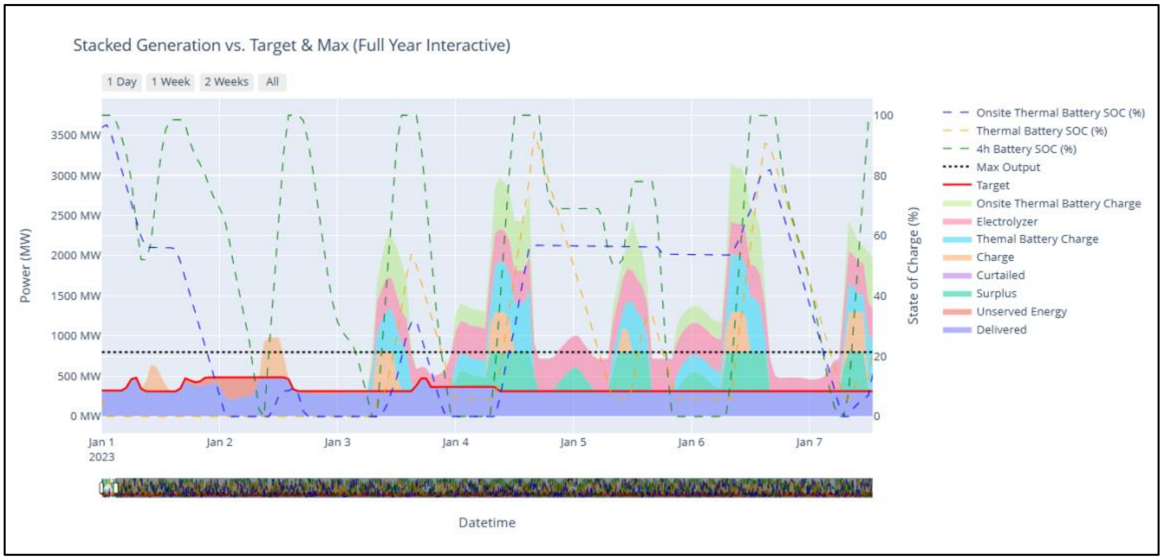
Electricity is available to the electrolyzer 65 percent of the time, well within the expected range for hydrogen electrolyzers of 50-75 percent capacity factor. The thermal batteries can operate with 97 percent up-time. Thermal output down-time can either be covered with a small backup boiler or scheduled maintenance (we expect at least a day of warning if not more, depending on the quality of weather forecasting, and energy deficits can be spread around various customers) for customers who need completely uninterrupted heat delivery. Another option would be to add thermal storage capacity by doubling up the thermal batteries. This improves the thermal output up-time to 99.2 percent, while giving a small boost to electrolyzer availability (+1.4 percent) and further reduction in curtailment (-1.5 percent of renewable energy production).

Component 4: Long-duration energy storage (on-site thermal batteries)

In this last run, we have all four components, and contrasting with previous runs we aim to illustrate how long-duration storage helps close the gap for meeting the target profile. Here, this is modeled by adding on-site thermal batteries, which can use their heat output to drive a steam turbine or use other more direct reconversion strategies such as electromagnetic radiation to electricity as pioneered by Antora. This final run includes another 20 thermal batteries located on-site at the Comanche power plant for up to 400 $MW_{thermal}$ output. This equates to about 160 MW/2,880 MWh of 18-hour backup electrical power via a 40 percent efficient steam turbine. At this small level, we cannot re-use the Unit 3 turbine but might be able to repurpose the soon-to-retire Unit 2 turbine. Adding 30 more thermal batteries and upping the turbine efficiency to 50 percent could bring Unit 3's turbine into play. The energy park would incur significant extra cost to target the larger turbine (~$450 million) but the reliability would improve to 99.7 percent while almost eliminating surplus and curtailed power (in fact, the energy park would probably be in a good position to absorb surplus and curtailed power from elsewhere on the bulk power grid).

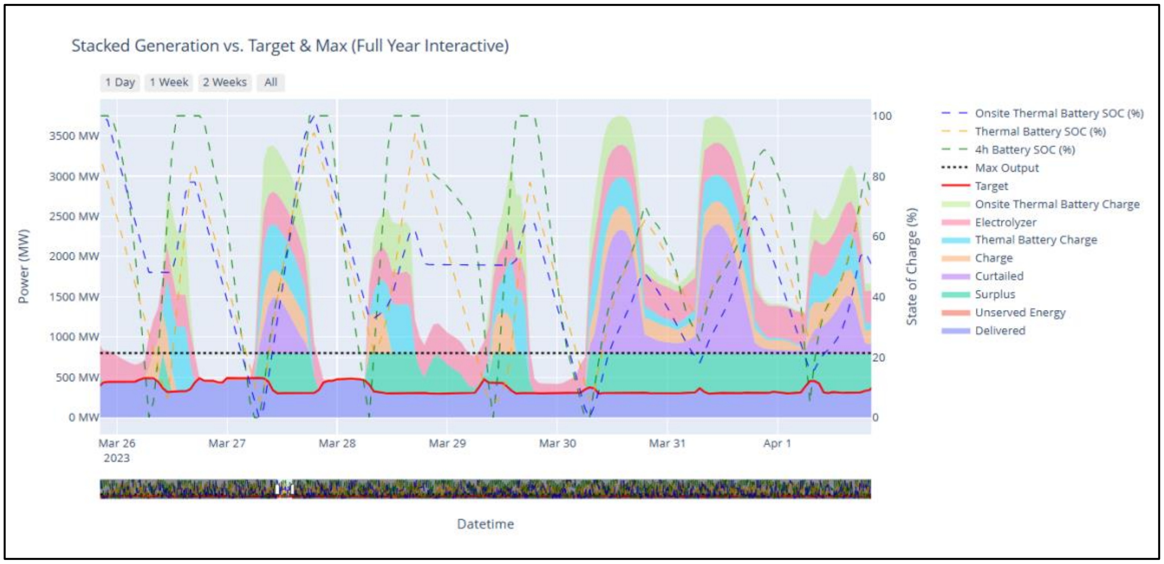
Returning to our main case, the final run, with ~2,880 MWh of extra backup electrical power, the previous 5,771 MWh deficit against target decreases to 2,733 MWh. The on-site thermal battery has a significant impact on unserved energy during the worst week and entirely removes deficits elsewhere in the year. More on-site thermal batteries, or a 280 $MW_{thermal}$ backup boiler that can stretch out the thermal supply, would fully eliminate the unserved energy.

Figure B8. First week of the year resource dispatch for Run 4



Meanwhile, as demonstrated in the early spring week, the on-site thermal batteries provide another avenue for storing energy that would otherwise be curtailed. This almost completely compensates for the standby and round-trip losses from holding and reconverting heat to electricity via a 40 percent efficient turbine.

Figure B9. Week following March 26 resource dispatch for Run 4



In the final annual breakdown of energy produced, the key metric to note is that the energy park is now technically at a 99 percent reliability level compared to the target profile. Meanwhile heat loads are well served, with 95 percent up-time for the thermal batteries, and the electrolyzers are receiving power well within requirements, at 70 percent. Note that these are all technical potentials for a set of resources. Capacity optimization could improve results, while including forecast errors and stochastic behavior will require more conservative scheduling and could lead to slightly less attractive results.

When anticipating how these results might apply in a real-word deployment, unknowns like electrical and power-flow constraints, transmission upgrade needs, and unknowns leading to forced outages are important to consider. Luckily, the granular and distributed nature of these resources (especially in the first three categories) leads to considerable redundancy. For example, if the solar capacity were split into six to seven installations of roughly 300 MW in size, many with their own battery capacity, the likelihood of their all going out of service at once would be minimal, while the impact of any one installation going out of service (planned or unplanned) could be managed by other parts of the energy park almost all the time. Hence, the actual reliability is likely to be close to the technical potential in our model runs. Compare that with most single fossil and nuclear plants. In its 2024 "State of Reliability Overview,"[1] the North American Reliability Corporation had a weighted forced outage rate of 11.7 percent for coal plants, 7.7 for gas plants, and 2 percent for nuclear plants. That does not include planned outages for maintenance and re-fueling (5 percent for nuclear as per NREL's Annual Technology Baseline). Further, an energy park could easily outperform these metrics via relatively inexpensive measures (like a backup boiler or extra batteries) to further boost reliability.

Run 4 Optimization Summary:

Total RE Produced (MWh): 9,834,720
Total Unserved Energy (MWh): 38,520
Total Delivered Energy (MWh): 3,374,062
Total Electrolyzer Delivered Energy (MWh): 2,476,913
Total Electricity Delivered to RHB (MWh_electric): 1,769,173
Total Curtailed Energy (MWh): 244,759
Total Surplus Energy (MWh): 1,166,319
Total Charging Energy (MWh): 854,192
Total On-site Heat Battery Charging Energy (MWH): 1,769,173
Unserved Energy (% of Annual Target): ***1.13%***
Battery Losses (% of Total RE): 0.87%
RHB Losses (% of Total RE): 0.96%
OB Losses (% of Total RE): 7.47%
RHB Thermal Delivery (% of Total RE): 17.09%
Delivered (% of Total RE): 34.31%
Electrolyzer (% of Total RE): 25.19%
Curtailed (% of Total RE): 2.49%
Surplus (% of Total RE): 11.86%
RHB Availability: 95.63%
Electrolyzer Availability: 70.69%

Modeling summary

Now that we have illustrated the role of each component with separate model runs, we look at the four runs in summary to put it all together.

Table B1. Summary of model run portfolios and reliability performance

	Energy and Capacity Resources						Reliability			
	Solar (MW)	Wind (MW)	4h Storage (MW)	Thermal Battery ($MW_{electric}$)	Electrolyzer (MW)	On-site Thermal ($MW_{electric}$)	% of Target Achieved	% Thermal Baseload Achieved	% Electrolyzer Availability	Gap to Target First 60 Hours (MWh)
Run 1	800	1,200					76%			13,741
Run 2	800	1,200	500				90%			11,712
Run 3	2,000	1,600	500	800	400		94%	97%	65%	5,777
Run 4	2,000	1,600	500	800	400	1600	99%	96%	71%	2,733

In Model Run 1, with only wind and solar generating resources, we have a base portfolio that produces 60 percent more energy on an annual basis than required for the target firm resource profile (double the actual delivered amount) while still resulting in 23 percent unserved energy. With just this component, the energy park performance is subpar and produces a lot of overgeneration. With the addition of our choice of a 4-hour battery component (Run 1 to Run 2), the delivered energy rises from 49 percent of total generated renewable energy to 58 percent, while energy that is generated in surplus of the target profile or curtailed is reduced. Importantly, unserved energy decreases significantly, from 23 percent in Run 1 to 10 percent, thanks to the ability of the lithium-ion batteries to shift wind and solar generation to match the target profile. We did not tune the battery duration, but rather simply modeled the selected technology of 4-hour batteries.

Figure B10. Unserved energy by model run

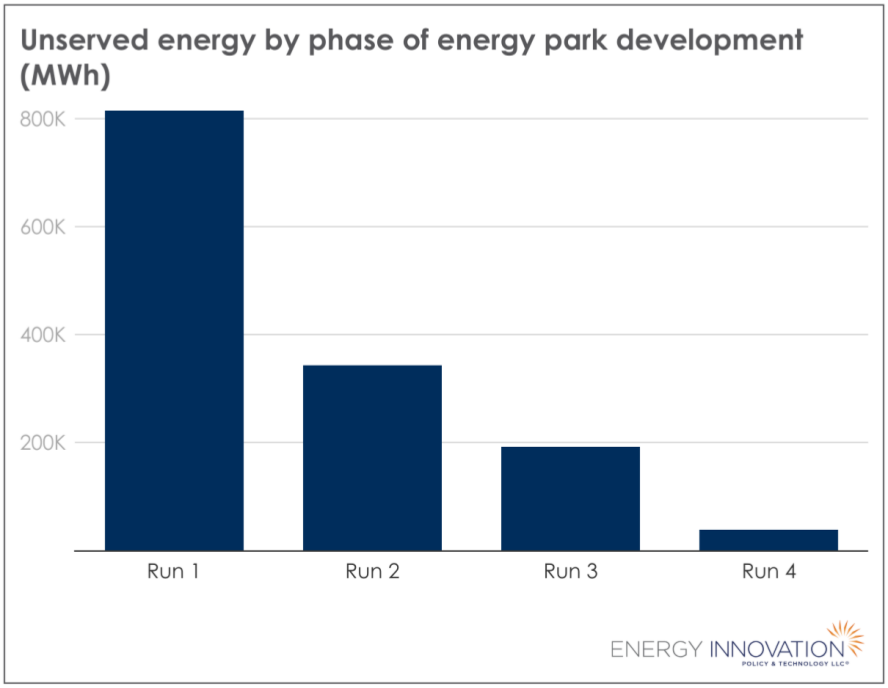
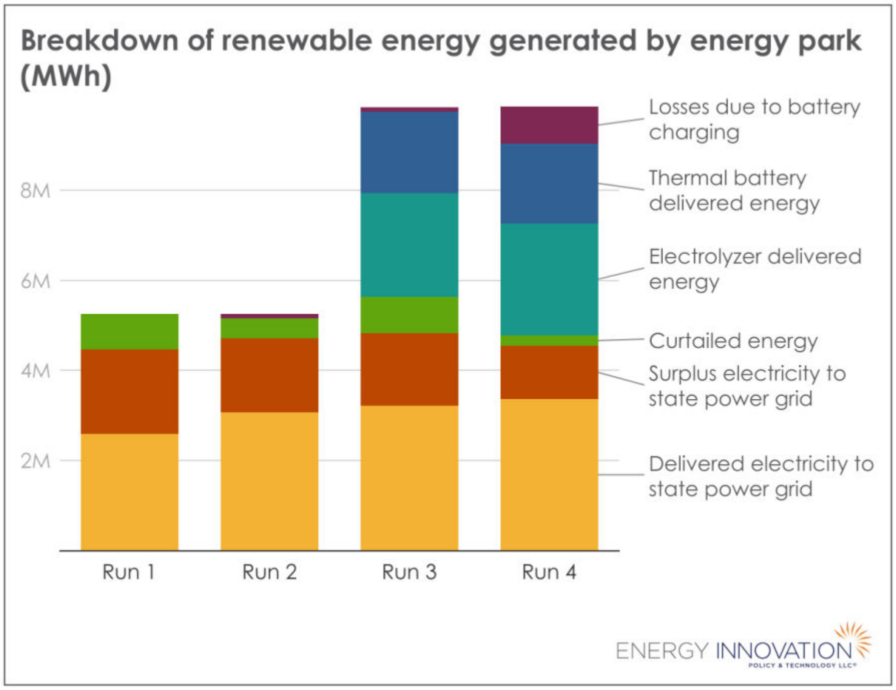


Figure B11. Breakdown of renewable energy generated by model run



Run 3 adds more solar (1,200 MW) and wind (600 MW) as well as flexible industrial loads in the form of thermal batteries that serve heat to industrial customers and electrolyzers that take in electricity and output hydrogen. Here, delivered energy increases by 200,000 MWh, though it decreases as total share of the energy generated (33 percent) due to electricity delivery to thermal batteries and electrolyzers (43 percent). The energy park is now delivering more annual energy to local industries than it exports to the grid—it has become an economic engine. Because the energy park can now generate additional electricity, however, unserved energy decreases again, now down to 5 percent of target demand.

The final run, Run 4, integrates all the elements of our energy park vision by adding 20 additional thermal batteries as long-duration storage on-site at Comanche that can reconvert heat to electricity to maximize reliability of the aggregate resource. Now, because so much energy can be stored in the thermal batteries for later use, surplus and curtailed energy are reduced to their lowest levels, and delivered energy reaches its maximum. While more energy is lost in battery round-trip efficiency, the portfolio's unserved energy falls to approximately 1 percent, significantly better than unserved energy when comparing Comanche Unit 3's 2023 output to the target profile, and even better than a well-functioning gas, coal, or nuclear plant. The long-duration storage also improves throughput to the bulk power grid and local Pueblo flexible industrial customers by 1 percent each.

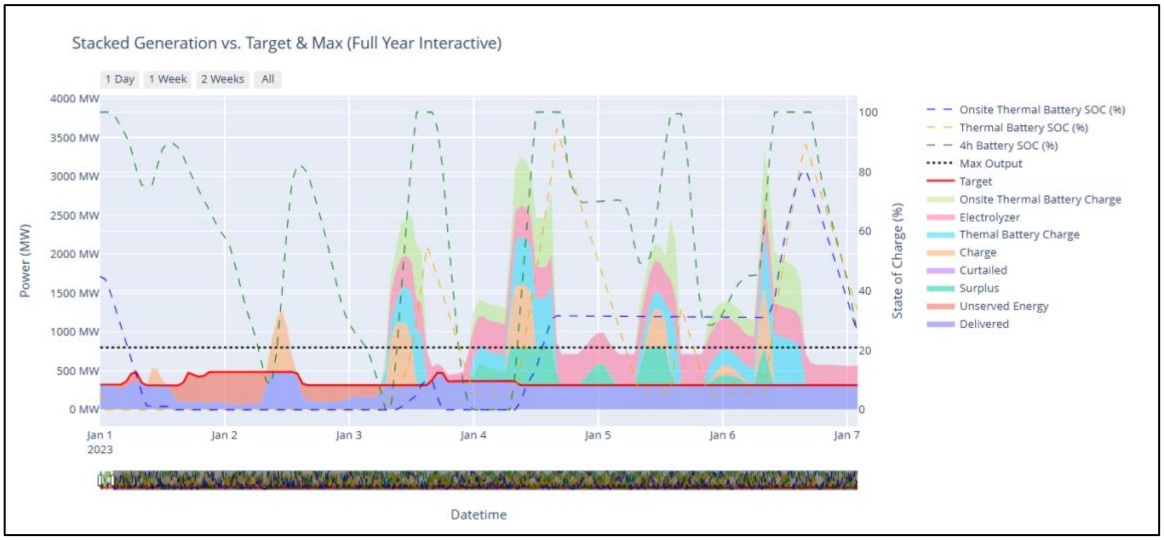
Table B2. Breakdown of renewable energy production by model run

	Total Renewable Production (MWh)	Target Delivered (MWh)	% of RE	Co-located Customers (MWh)	% of RE	Surplus	% of RE	(Curtailment + Losses) (Wasted MWh)	% of RE
Run 1	5,247,532	2,597,151	49%		0%	1,863,172	36%	787,209	15%
Run 2	5,247,532	3,068,961	58%		0%	1,648,313	31%	530,259	10%
Run 3	9,834,720	3,219,741	33%	4,092,616	42%	1,610,503	16%	1,002,158	10%
Run 4	9,834,720	3,374,062	34%	4,246,075	43%	1,166,319	12%	1,128,042	11%

Data center scenario

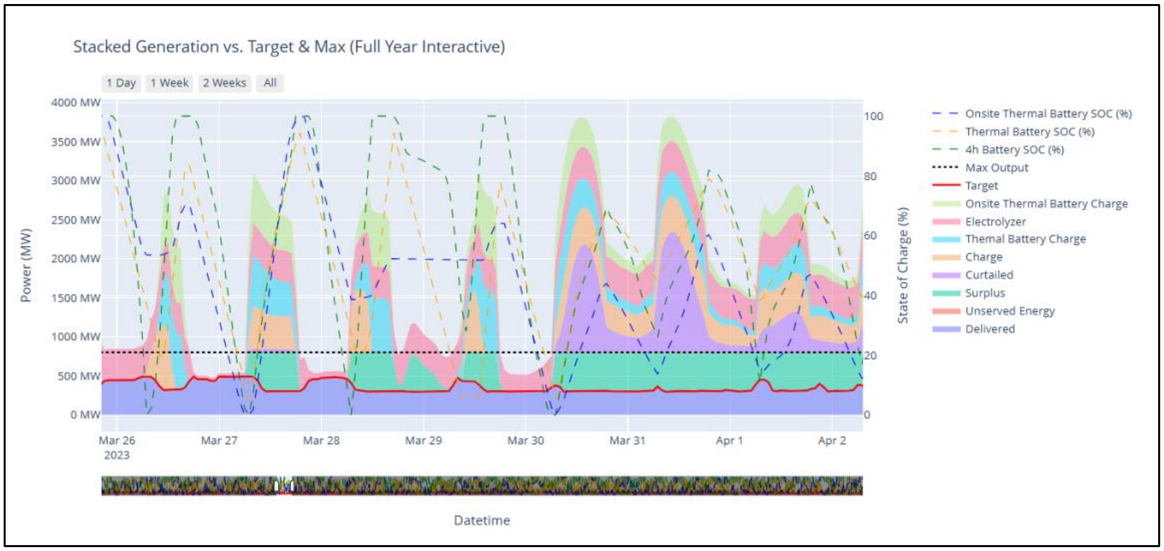
Given the reliable output of the energy park, it is interesting to consider adding a load that isn't flexible, like a data center with a 100 percent up-time requirement. We don't discuss this option in the main report but include it here for curious readers. For example, to serve a new 200 MW data center load, we model adding 300 MW solar and 300 MW wind, 20 on-site Rondo RHB 300 batteries, and 6 hours (of data center demand) of lithium-ion storage (300 MW/1,200 MWh). This is a substantial investment (around $2.5 billion, or $1.5 billion after applying the federal investment tax credit) to provision the data center, but this is still competitive for such a customer at ~$60-70/MWh. A straight 200 MW gas solution would be more than $400 million in equipment before fuel expenses, gas pipeline extensions, and air permits but comes with lower reliability.

Figure B12. First week of the year resource dispatch for data center scenario



Continuing our plots (we don't include the data center load in the plot; it's a flat uninterrupted 200 MW block), we can see how this extra addition affects our energy park. In the early days of the year, the need to funnel all available resources to ensure the data center runs at full capacity detracts from the energy park's performance, increasing the gaps against target (9,846 MWh over the first three days). However, the extra batteries continue to eliminate curtailment and reduce surplus later in the week

Figure B13. Week following March 26 resource dispatch for data center scenario



In early spring we see no new gaps emerge, and again all that extra storage helps reduce curtailment and some surplus. The peak curtailments for the year are more than halved by our flexible loads, even with the extra generation. Overall, the annual statistics tell a story of very marginal effects on the reliability of the energy park.

Reliability drops from 99 percent to 98.5 percent, but losses and curtailment remain around 10 percent combined. We reduce surplus energy, but thermal output and electrolyzer availability drop a bit (more generation might help). At this point, the challenge is less technical and more economic: how much do consumers want to spend for a small marginal improvement in clean firm power availability? Also, if the data center can flex electricity use even moderately (for example, reduce output for 50-100 hours a year[2]), unserved energy could be eliminated. Alternatively, other solutions could be deployed to back up the energy park (like a slightly bigger backup boiler at the park). Overall, the combination of on-site or nearby generation and storage resources could obviate the need for dirty and expensive diesel backup generation.

No flexible load, increased long-duration storage scenario

Here we consider a corner-case sensitivity where Xcel/PSCo is unable to engage flexible industrial consumers and depends only on long-duration storage at the Comanche Unit 3 site along with short-duration batteries at Comanche and the various renewable generation installations connected to it. With the base renewable portfolio, the 500 MW battery and 40 on-site thermal batteries (3,200 MW in, 320 MW out), we can maintain decent reliability (98 percent), but we once again have a huge surplus (27 percent of annual renewable energy)—opportunities that are no longer captured by the Pueblo community. If we try to downsize from the base portfolio (700 MW solar/900 MW wind) to reduce surplus exports to 17 percent of annual renewable energy (the long-duration storage still captures most of the curtailed power), the reliability starts to drop (94 percent). While these scenarios may seem attractive because the total absolute portfolio expense is much lower, average levelized cost of energy for the power exported to the grid is worse than for our main case, and matters get even worse if the surplus power is discounted (delivered power ~ $80/MWh with surplus valued at $15/MWh).

Skipping the opportunity to engage with Pueblo industry as a source of flexible load may hit operational milestones, but it is a lose-lose for Xcel customers and the Pueblo community.

APPENDIX C: PROPERTY TAX AND COST ASSUMPTIONS

Property tax assumptions

We use the "cost" method for calculating property taxes for the thermal batteries supplying heat, as well as the electrolyzers. We use a mill levy of 9.55 based on the county assessor's value at the Comanche power plant site and depreciate the assets from 95 percent of the cost to install to 20 percent over 30 years. See below for cost assumptions used for each technology.

We use the "income" method for calculating the property taxes for the wind, solar, lithum-ion batteries, and thermal batteries located at the Comanche coal plant site that can reconvert heat to electricity. Here, we use the Colorado tax assessor's tool to calculate the state assessed values by capacity of the resources.[viii]

Cost assumptions

Table C1. Cost allocation assumptions by resource

	Up-Front Capital Cost	Fixed O&M Cost	Source
Solar	1,380 ($/kW)	20 ($/kW-year)	NREL ATB
Wind	1,500 ($/kW)	30 ($/kW-year)	NREL ATB
4-hour battery	1,660 ($/kW)	41.50 ($/kW-year)	NREL ATB
RHB 300 thermal battery	15,000,000 ($/unit)	300,000 ($/unit-year)	Private communications

[viii] https://dpt.colorado.gov/renewable-energy

Electrolyzer + balance of system	2,500 ($/kW)		Estimated based on many reports
Small modular reactor	20,129 ($/kW)	$115 ($/kW-year)	Estimated based on NuScale, Breakthrough Institute[29]

Table C2. Other assumptions

Heat price	30 ($/MWh)	
Electricity price to electrolyzer	45 ($/MWh)	
Capital recovery factor	8% per year	
Surplus electricity price	15 ($/MWh)	
Small modular reactor fuel cost	8.71 ($/MWh)	Breakthrough Institute, estimated based on NuScale
Small modular reactor capacity factor	95%	

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