Solar Energy Zone Market Analysis for the San Luis Valley Region of Colorado

David Hurlbut, Heather Buchanan, and Jesse Cruce

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List of Acronyms and Abbreviations

AC	alternating current
ALJ	administrative law judge
BLM	Bureau of Land Management
Btu	British thermal units
CEP	Clean Energy Plan
CPCN	certificate of public convenience and necessity
CPUC	Colorado Public Utilities Commission
DC	direct current
DNI	direct normal irradiance
DSM	demand-side management
EIA	U.S. Energy Information Administration
ERP	Electric Resource Plan
FERC	Federal Energy Regulatory Commission
GHI	global horizontal irradiance
GW	gigawatts
kV	kilovolts
kW	kilowatts
L&R	load and resource
MVA	millivolts ampere
MW	megawatts
PAGS	Pueblo Airport Generating Station.
PON	Poncha Springs
PSC	Colorado Public Utilities Commission
SAM	System Advisor Model
SEZ	solar energy zone
SLV	San Luis Valley
SLVREC	San Luis Valley Rural Electric Cooperative
TSGT	Tri-State Generation and Transmission Association
TWh	terawatt-hours
WAPA	Western Area Power Administration

Executive Summary

This report examines the commercial viability of solar energy zones (SEZs) in the San Luis Valley of Colorado (the valley) based on market conditions in 2022. The Bureau of Land Management may designate a SEZ on federal land to expedite environmental review and permitting for solar energy projects. BLM defines a SEZ as "an area well suited for utility-scale production of solar energy, where the BLM will prioritize solar energy and associated transmission infrastructure development."[1]

The market demand for a solar project built in a San Luis Valley SEZ is uncertain at this time. Many alternatives exist in Colorado that can serve the same demand at the same cost but with fewer transmission limitations. The game-changing factor would be a decision by Xcel Energy and the Tri-State Generation and Transmission Association to upgrade the 230kV line from the valley to Poncha Springs, Colorado, which would add as much as 600 MW of new export capacity, or four times the solar capacity currently in the valley.

General observations include:

- Load-serving utilities in Colorado anticipate future demand for more renewable resources, and the expected cost of new solar projects sited in the valley is less than the utilities' current cost of electricity.

- Transmission continues to be the biggest obstacle to additional solar development in the valley. As of this writing, however, the valley's transmission-owning utilities have filed no proposal to upgrade the lines that connect the valley with the rest of the Colorado grid. The utilities have studied upgrades to improve the reliability of service to retail customers in the valley. Though these upgrades would significantly increase export capacity out of the valley, the main consideration for the upgrades is reliability—not increased renewable energy development. Utilities routinely compare transmission upgrades with non-wires alternatives when evaluating how to manage reliability in a cost-effective manner.

- Solar exposure is about the same in the San Luis Valley SEZ as it is east of the Front Range in southeastern Colorado. This implies that a solar plant built in southeastern Colorado could produce as much electricity per megawatt of capacity as could the same plant built in a San Luis Valley SEZ. Xcel Energy has filed an application to add transmission in eastern Colorado that would enable more solar and wind development in the southeastern part of the state.

[1] BLM, *Approved Resource Management Plan Amendments/Record of Decision (ROD) for Solar Energy Development in Six Southwestern States*, October 2012.

Table of Contents

List of Figures

List of Tables

1 Introduction

This report examines the commercial viability of solar energy zones (SEZs) in the San Luis Valley of Colorado (the valley) based on market conditions in 2022. The Bureau of Land Management (BLM) may designate a SEZ on federal land to expedite environmental review and permitting for solar energy projects. BLM defines a SEZ as "an area well suited for utility-scale production of solar energy, where the BLM will prioritize solar energy and associated transmission infrastructure development."[2] The purpose of the analysis reported here is to understand whether current market conditions support the need for SEZs in the valley.

The analysis includes three parts:

- **An Assessment of Demand:** Who are the load-serving utilities (or other potential energy purchasers) that might want the output from a solar project in the SEZ? Have they indicated any desire for new power purchase agreements for energy?
- **An Assessment of Transmission:** Is it possible to get energy from the SEZ to market via existing transmission? Is there existing transmission near the SEZ, and if so, does it have available transfer capability sufficient to accommodate the potential SEZ development?[3]
- **An Assessment of Project Viability:** Is it likely that a SEZ solar project could provide energy to load-serving utilities at a lower cost than what the utilities could procure from non-SEZ projects? Does the SEZ have terrain that would increase the cost of development? Is the annual solar exposure better or worse than at other potential sites?

Figure 1 illustrates how these three factors affect the likelihood that a SEZ will stimulate commercial interest among solar project developers. If there is no proximate market appetite for a SEZ project, if there is no way to get the energy to market, or if there are simply better opportunities elsewhere, developer demand for SEZ land will be weak and a competitive auction for the SEZ might draw little interest. Only if all three factors are positive will there be predictable developer interest.

[2] BLM, *Approved Resource Management Plan Amendments/Record of Decision (ROD) for Solar Energy Development in Six Southwestern States*, October 2012.

[3] Available transfer capability is a line's total capability in megawatts, minus the megawatts of capability already obligated to other transmission customers.

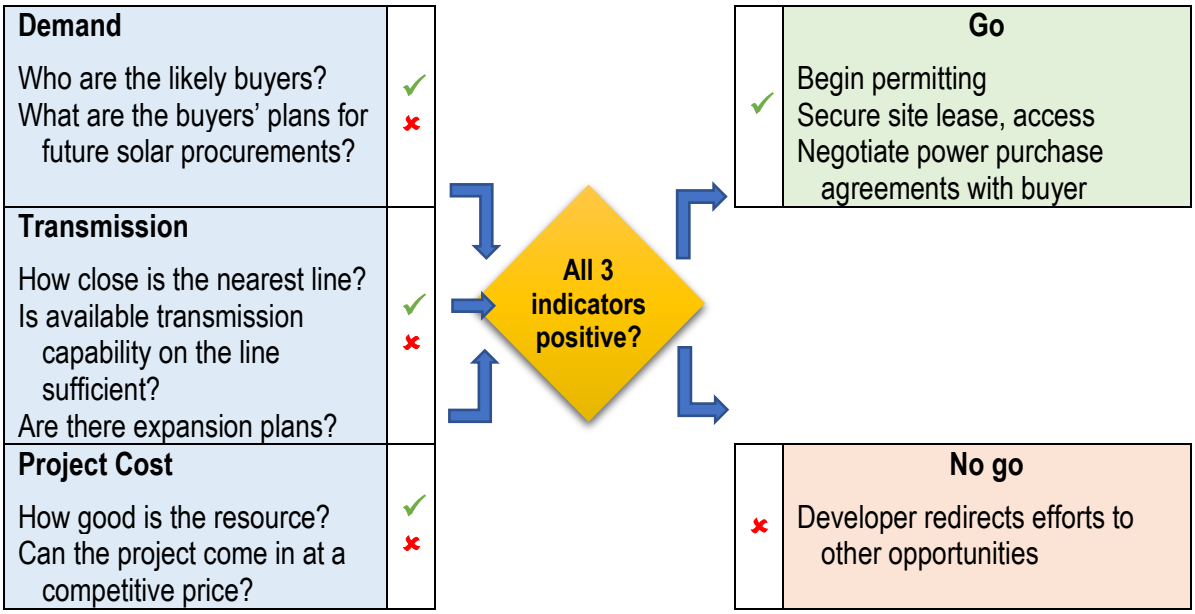


Figure 1. Decision steps for solar project viability

Table 1 shows the answers to some of the key market questions posed in Figure 1. Xcel Energy (Xcel), which serves customers in the Denver metro area as well as parts of the valley and western Colorado, is the offtaker for renewable energy in the state due to the size of its customer base, the state renewable energy mandate, and corporate goals. Several retail electric cooperatives, including some served by the Tri-State Generation and Transmission Association (Tri-State), have individual renewable energy goals.

Xcel Energy's overall cost of generation for 2021 was $57/MWh. This includes fuel costs for all generators in its fleet, the cost of power purchased from renewable energy providers and other merchant generators, the cost of reliability services, and other direct costs. A typical solar project built in a San Luis Valley SEZ could potentially provide energy at a cost lower than Xcel Energy's benchmark. The next section looks more closely at whether Xcel Energy or other utilities are currently in the market for more renewable energy resources.

Two utilities—Xcel and Tri-State—own different parts of the transmission network in the valley. Xcel's retail service territory includes the Denver metro area, parts of the valley, and parts of western Colorado. Tri-State is a generation and transmission electric cooperative serving more than 40 distribution cooperatives in Colorado, New Mexico, Wyoming, and Nebraska, including the San Luis Valley Rural Electric Cooperative. Colorado Springs Utilities and Black Hills Energy (serving Pueblo) are also connected to the Xcel and Tri-State systems.

Table 1. Market Characteristics Affecting Demand for Solar Projects in the San Luis Valley

	Utility	Retail sales[a] (TWh, 2021)	Revenue (¢/kWh, 2021)
Nearest Customer-Serving Utilities with the Largest Load	Xcel Energy (Metro Denver)	28.9	10.5
	Colorado Springs Utilities	5.0	10.4
	Black Hills Colo. Energy (Pueblo)	1.9	14.2
Utilities' Average Electricity Production Cost (2021)[b]	Xcel Energy	$57/MWh (5.7¢/kWh)	
	Tri-State	$58/MWh (5.8¢/kWh)	
	Black Hills Energy	$89/MWh (8.9¢/kWh)	
Estimated Levelized Cost for a Typical Solar Project in a San Luis Valley SEZ		$36–$46/MWh (3.6¢–4.6¢/kWh)	
Transmission Utilities with Lines near San Luis Valley SEZs	Xcel Energy		
	Tri-State Generation and Transmission Association		
	Western Area Power Administration		

[a] U.S. Energy Information Administration, EIA Form 861M database (2021 data for retail sales, average rates).

[b] Public Service Company of Colorado (Xcel Energy), 2021 Federal Energy Regulatory Commission (FERC) Form 1 (2022); and Black Hills Colorado Electric, 2021 FERC Form 1 (2022); figures shown are total power production expenses (page 320, line 80) divided by total energy sold to retail customers (page 304, line 43), including the cost of purchased power. Tri-State Generation and Transmission Association, 2021 FERC Form 1 (2022); figure shown is total power production expenses divided by energy delivered to distribution co0operatives (page 310, line 15).

1.1 Characteristics of the San Luis Valley SEZs

Figure 2 shows the valley and the transmission paths from it to load centers in the east. The red areas indicate currently designated SEZs in the valley. Note that the only transmission egress is to the north, where lines from the valley join with a corridor connecting to Pueblo, Colorado Springs, and Denver. There is no connection south to New Mexico.

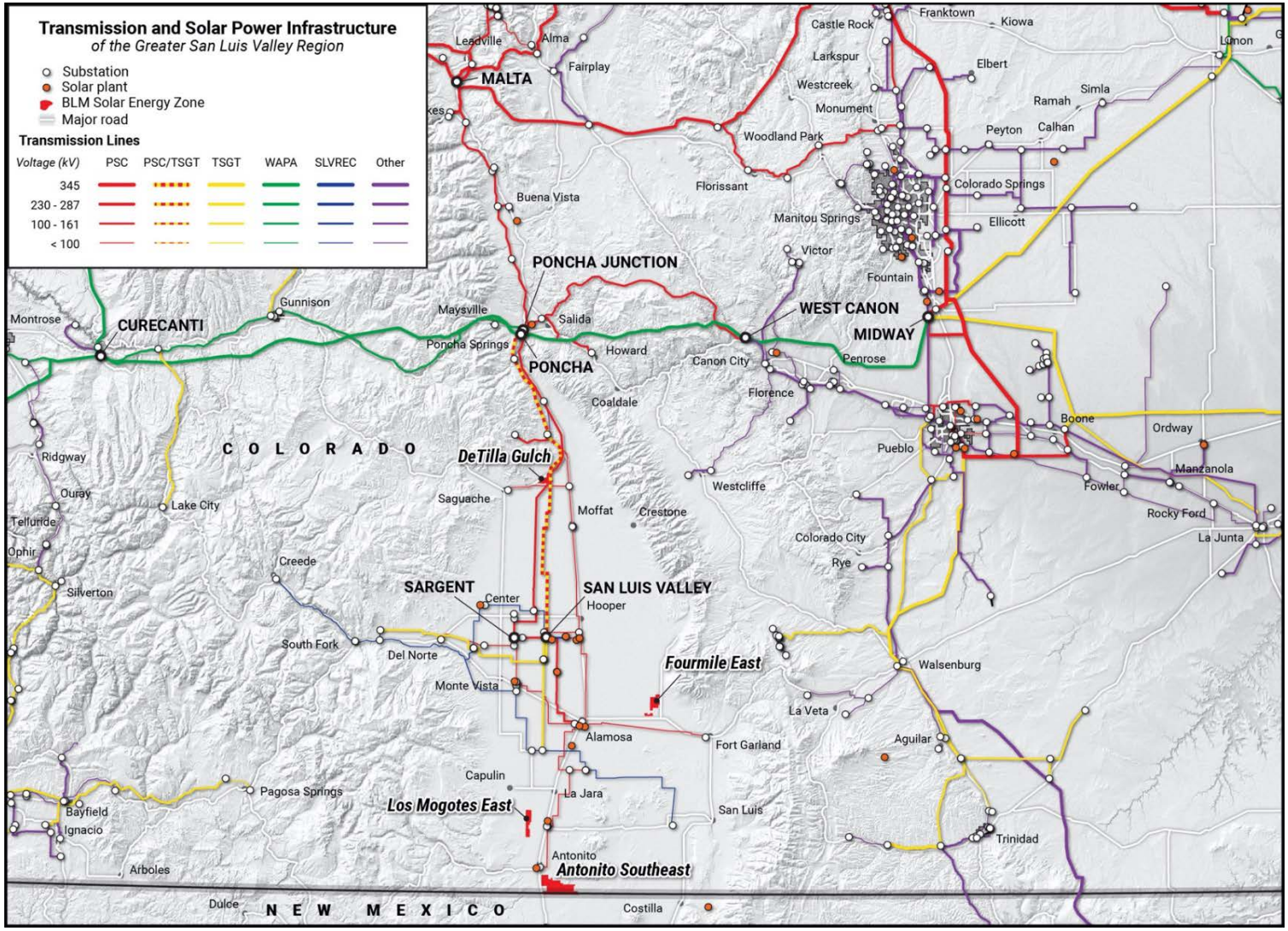


Figure 2. San Luis Valley, location of SEZs, and transmission lines

NREL map by Billy Roberts. PSC is Public Service Company of Colorado, Xcel's operating company in Colorado. SLVREC is the San Luis Valley Rural Electric Cooperative. TSGT is the Tri-State Generation and Transmission Association. WAPA is the Western Area Power Administration.

The San Luis Valley is served by two transmission lines (230kV and 115kV) that run north from the valley to Poncha Springs, Colorado, where they connect with the rest of the grid. A third (69kV) line also follows this corridor, but it serves only local loads. Customers in the valley are served by 69kV and 115kV radial lines. At Poncha Springs, a 115kV line and a 230kV line connect east to Pueblo, while a second 115kV line connects north to Malta and Leadville, Colorado, and ultimately the Denver metro area.

The valley itself, which is sunnier than the northern half of the state, has some of the best solar resource in the state of Colorado. Its three largest projects (52, 35, and 30 MW) were built between 2011 and 2015. The area also has 11 projects that are 10 MW or smaller; the most recent was added in 2021, bringing the valley's total installed solar capacity to 156 MW.[4] None of the existing projects were built in a SEZ.

In 2009, Xcel and Tri-State filed a request with the Colorado Public Utilities Commission to build a new 230kV connection from the valley eastward across the Sangre de Cristo Mountains and connecting near Walsenburg, Colorado. The utilities abandoned the plan in 2011 after opposition from a key landowner. The situation affected solar development in the valley, and it provides a case study of the difficulties that can arise with new transmission development. For more information, see Appendix A.

1.2 Need for Future Updates

The findings of this study are valid for the current market conditions, but should be revisited as circumstances change. Utilities account for future load growth, plant retirements, and regulatory requirements when determining their future procurement needs, and this study reflects the current outlooks of the relevant utilities. All the load-serving utilities that could purchase solar power generated in the valley maintain integrated resource plans. Changes in market conditions that would affect a utility's procurement plans should be reflected in the utility's integrated resource plan.

[4] Energy Information Administration, EIA Form 860M, February 2022.

2 Demand for New Solar Energy Projects

The resource plans of some of the major utilities in and near the valley show that they are anticipating an increase in solar deployment in the state in the coming years. One factor driving these plans is Colorado's renewable energy standard and carbon reduction goals, which require utilities to reduce their carbon dioxide emissions associated with electricity sales by 80% from 2005 levels by 2030 and by 100% by 2050.[5] In addition, Xcel noted in its plan that a lack of transmission lines in the valley is limiting the ability to harness solar resources in the region.

2.1 Public Service Company of Colorado (Xcel Energy)

Public Service Company of Colorado (Xcel Energy) submitted its most recent Electric Resource Plan (ERP) to the Colorado Public Utilities Commission (CPUC) on March 31, 2021. When Xcel prepared its ERP, it included an assessment of future need for additional generation capacity on the system ("load and resource balance," or L&R). Xcel determines whether it needs additional generation capacity for system reliability by forecasting whether it can maintain sufficient planning reserve margin[6] throughout each summer peak season through the resource acquisition period.

Colorado Senate Bill 19-236 (S.B. 19-236) required Xcel to clearly differentiate the resources required to meet customer demands in the resource acquisition period and additional need created by Xcel's actions in furtherance of the 80% clean energy target, such as retiring existing generating facilities or changes in system operations. Xcel developed two sets of portfolios to address these requirements: ERP portfolios and Clean Energy Plan (CEP) portfolios. The ERP portfolios meet the L&R's base need (which accounts for previously announced retirements of the Craig 2, Hayden 1, and Hayden 2 coal units) and are not required to meet the 80% carbon reduction by 2030 target. The CEP portfolios reflect both the additional coal unit retirements at Pawnee and Comanche 3 as well as additional resource acquisitions needed to meet the 80% carbon reduction by 2030 target. Both the ERP and the CEP portfolios are carbon free by 2050 (Xcel 2021).

Table 2 shows a summary of Xcel's net generation position forecasted for the resource acquisition period. The table also shows the expected impact of recently announced coal unit retirements.

[5] S.B. 19-236, 70th Gen. Assemb., Reg. Sess. (Colo. 2019).
[6] Xcel proposed using an 18% planning reserve margin.

Table 2. Xcel Generation Capacity Needs (MW)

(needs as of summer of year shown)

		2022	2023	2024	2025	2026	2027	2028	2029	2030
Starting Capacity Need long / *(short)*		**296**	**210**	**61**	**17**	*(203)*	*(672)*	*(1,354)*	*(1,411)*	*(1,474)*
Announced early coal retirements	Craig 2								(40)	(40)
	Hayden 1								(135)	(135)
	Hayden 2							(98)	(98)	(98)
Capacity Needs with Announced Retirements long / *(short)*		**296**	**210**	**61**	**17**	*(203)*	*(672)*	*(1,452)*	*(1,684)*	*(1,747)*

Source: Xcel 2021

Xcel's resource need assessment resulted in the following conclusions:

- Xcel does not anticipate any need for additional generation capacity to maintain acceptable system reliability from 2021 to 2025, but need is projected to increase each year from 2026 to 2030.
- Xcel anticipates no need for additional renewable resources to meet the "minimum amounts" reflected in the renewable energy standard.
- The volume of flexible resources needs to accommodate up to 3 gigawatts (GW) of incremental wind generation, according to Xcel's updated Flex Reserve analysis.
- There is a need for additional emission reduction efforts to meet S.B. 19-236's 2030 clean energy target (Xcel 2021).

Xcel's ERP portfolio includes adding 1,150 MW of utility-scale solar resource. In addition, the CEP portfolio optimizations considered each of the different coal transition possibilities for Pawnee and Comanche 3. A recent settlement agreement between Xcel and several stakeholders provides for retiring the Comanche 3 unit by 2031, and competitive solicitations for zero- and low-emission resources to replace it (Xcel 2022).

The lack of transmission in eastern and southeastern Colorado limits the ability to harness potential solar resources in those regions. On March 2, 2021, Xcel filed a Certificate for Public Convenience and Necessity (CPCN) application for a 560-mile, 345kV transmission line called the Colorado Power Pathway Project (Xcel 2021). It is made up of five segments that would include a high-voltage transmission facility to interconnect eastern and southeastern Colorado to Xcel's load centers, which could allow developers to potentially develop and bid cost-effective projects into the "renewable rich" region. The project would start at the existing Fort St. Vrain Generating Station in Platteville, Colorado, and then go east to a new substation near Pawnee, Colorado, and east/southeast to near the Cheyenne Ridge Wind Project, south to near Lamar, Colorado, west to the Tundra Substation, and then north to the existing Harvest Mile Substation in Aurora, Colorado.

The CPCN application included a request for the CPUC to consider an extension to the Pathway Project. The May Valley-Longhorn Extension would be a 90-mile, 345kV transmission line from

the new May Valley Substation (at the southeastern corner of the Pathway Project near Lamar) south to the new Longhorn Substation near Vilas, Colorado (Xcel 2021).

Though Xcel plans to acquire an additional 1,550 MW of utility-scale solar through 2030 and recognizes the potential of solar resources in the valley, it also acknowledges the limits of current transmission infrastructure to support solar development in the region.

2.2 Black Hills Colorado Electric

Black Hills Colorado Electric (Black Hills) submitted its most recent electric resource plan to the Colorado Public Utilities Commission (CPUC) on June 3, 2016; it plans to file an update in 2022 (Black Hills 2016). The 2016 plan's forecast for net peak demand in 2021 was within 1.5% of the actual peak demand that the utility reported in its FERC Form 1 for 2021 (Black Hills 2021; Black Hills 2022).

Black Hills (2016) noted it was planning to acquire 60 MW of wind resources in 2019, which would allow it to acquire all the renewable energy certificates required by Colorado's renewable energy standard through 2025. Black Hills met this goal by bringing the Busch Ranch II Wind Project online in 2019 with a nameplate capacity of 60 MW (Black Hills 2019). Black Hills predicts that starting in 2026, it will likely need to acquire more eligible energy resources to stay in compliance, but those plans will be in the next iteration of the utility's resource plan. Black Hills does not own any oil-fired generating units, and it retired its coal-fired generation at the end of 2013 (Black Hills 2016).

The utility announced in 2021 that it planned to file a clean energy plan with the CPUC in 2022 (Black Hills 2021). Table 3 shows Black Hills' most recent published load and resource balance through 2022. Based on modest load growth, Black Hills projects that it would not have a capacity deficit until 2029. Its available capacity would continue to grow by a few megawatts each year until 2032, when a contract for 200 MW would expire (Black Hills 2016). Black Hills is working to add an additional 200-MW utility-scale solar facility in Pueblo County that is scheduled to come online in late 2024.

Table 3. Black Hills Load and Resource Balance (MW)

	2016	2017	2018	2019	2020	2021	2022
Peak demand	398	403	408	413	418	417	414
Demand-side management	-3.1	-8.5	-14.2	-16.7	-16.7	-16.7	-16.7
Net peak demand	395	395	394	396	401	401	397
Total resources	213	267	267	267	267	267	267
Renewable resources	*3.3*	*17.1*	*17.1*	*17.1*	*17.1*	*17.1*	*17.1*
Total resources and purchases	481.2	485.0	480.5	480.5	480.5	480.5	480.5
Total capacity requirement (peak plus 15% reserve margin)	454.6	454.0	452.9	456.0	461.0	460.7	456.6
Margin in excess of total capacity requirement	6.7%	7.9%	7.0%	6.2%	4.9%	4.9%	6.0%

Source: Black Hills 2016

2.3 Tri-State Generation and Transmission Association

Tri-State Generation and Transmission Association, Inc. (Tri-State) is the primary power supplier for several distribution cooperatives and rural electricity associations in Colorado, New Mexico, Wyoming, and Nebraska. Tri-State submitted its most recent Electric Resource Plan to the CPUC on December 1, 2020. When Tri-State prepared its ERP, it included an assessment of future need for additional generation capacity on the system. Using a bottom-up approach based on its historical Utility Member System forecasts that were combined to form regional forecasts, Tri-State developed a system load forecast through 2030. Tri-State did not indicate a capacity resource need until the year 2029 (Tri-State 2020).

Tri-State announced several key retirements in its 2020 ERP, including the Escalante Generating Station in 2020, and all three of the Craig Generating Station units by 2030. In addition, Tri-State plans to add 1 GW of renewables by 2024. It also outlined additional renewable resources forecast for development in the preferred plan to meet near-term emissions reduction goals (Tri-State 2020). Though Table 4 shows several solar resources forecast for deployment between 2026 and 2030, Tri-State said in its current ERP that later filings would address additional resource needs.

Table 4. Tri-State Preferred Plan for Solar Resources in Western Colorado, 2026–2030

Year	Capacity (MW)
2026	200
2027	100
2028	200
2029	200
2030	250

Source: Tri-State 2020

3 Transmission Capability

Transmission capacity within the valley is limited with respect to both reliability and transfer capability. The Colorado Coordinated Planning Group determined that a line upgrade within the valley would both alleviate reliability concerns and increase export capacity out of the valley significantly. However, the utilities that would build and own the new line have not decided whether to proceed with the upgrade, and as of this writing they were continuing to explore other, lower-cost options to improve reliability (SLV Subcommittee 2016; 2017).

Current transmission capabilities and system condition information is most readily available in the 2016 and 2017 transmission planning reports by the San Luis Valley Subcommittee of the Colorado Coordinated Planning Group, which includes Tri-State, Xcel Energy, and the Western Area Power Administration (WAPA). [7]

Two transmission lines currently connect the valley north to Poncha Springs and the rest of the grid: a 115kV line (owned by Xcel Energy) and a 230kV line (jointly owned by Xcel Energy and Tri-State). In Poncha Springs, a 230kV line (WAPA) runs west-east from Curecanti National Recreation Area to Canyon City and Pueblo, Colorado, and a second 115kV line (WAPA) connects Curecanti to Poncha Springs via Gunnison, Colorado. Two 115kV lines (Xcel Energy) also connect Poncha Springs east to Canyon City (normally open) and north to Malta (Leadville).

Loads within the valley are served by 69kV and 115kV radial lines, primarily from the SLV (San Luis Valley) Substation and the Sargent Substation. A 69kV line (owned by Xcel Energy) also connects to Poncha Springs, but this line is normally open at the north end of the valley due to thermal limits during contingency (line outage) conditions, and thus serves only local loads.

Contingency conditions—especially the loss of the 230kV from Poncha Springs into the valley—can require significant load shedding when net imports exceed 65 MW. For comparison, loads in the valley exceeded this threshold about 15% of the hours (across 40% of the days) in 2014 and 2015. Loads above this threshold almost exclusively occur in the spring and summer and are associated with crop irrigation during these seasons. Peak loads typically range from 130 MW to 150 MW (the SLV Subcommittee used 150 MW as the peak load for their analysis and planning). Two outages (and load shedding events) occurred between 2012 and 2017: one lasting 5 minutes and the other about 2 hours (Tri-State 2017; SLV Subcommittee 2016).

Export capacity from the valley to the Front Range urban corridor is limited by both in-valley and out-of-valley lines and substations. The current total transfer capacity out of the valley is 94.5 MW, and it is limited by the 115kV Sargent-to-Poncha line (Xcel) and the contingency loss of the existing 230kV line. Additional transmission transfer capacity and available transfer capacity information is shown in Table 5.

[7] The Colorado Coordinated Planning Group is a joint planning group that includes six other utilities in addition to Xcel, Tri-State, and WAPA.

Table 5. Transmission Transfer Capacities Into and Out of San Luis Valley

Line	Owner	Direction	Transmission Transfer Capacity	Available Transfer Capacity
Existing SLV 230kV	Tri-State	SLV to PON (out of valley)	47 MW	47 MW
		PON to SLV (into valley)	90 MW	11 MW
Xcel north/south lines (115kV & 230kV)	Xcel	SLV to/from Malta	91 MW	(not listed)
West/east 230kV	WAPA	Poncha to Midway (Pueblo)	250 MW	0 MW
Total System		**Out of valley to Poncha**	**94.5 MW**	
Total System		**Poncha to Front Range**	**252 MW–426 MW**	

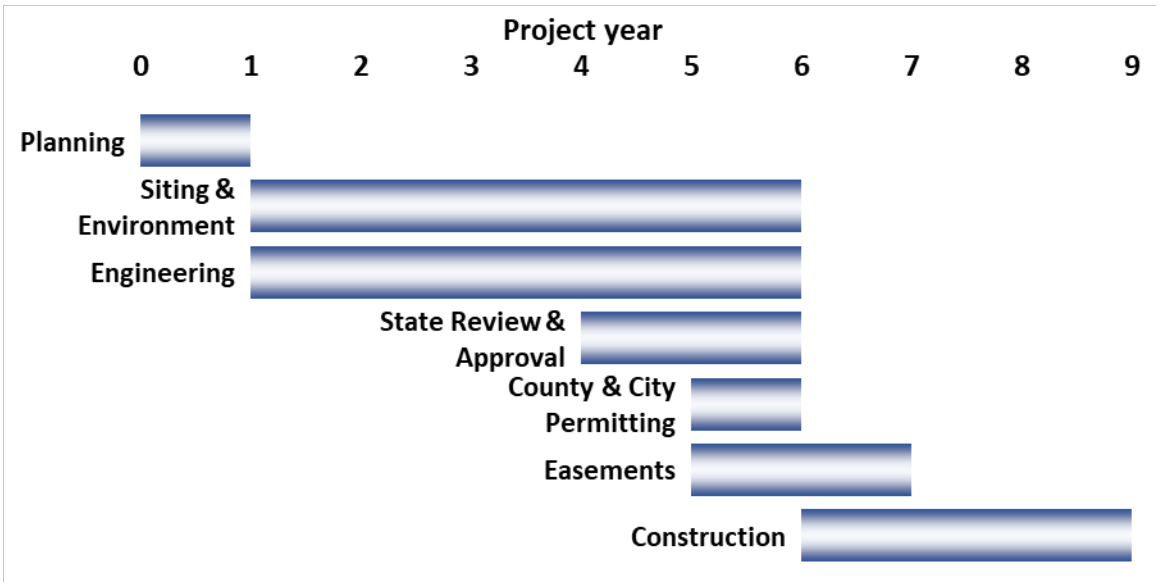
Source: SLV Subcommittee 2016; 2017; Open Access Same-Time Information System (oasis.oati.com); values confirmed by representatives from Tri-State, Xcel, and WAPA.

PON is Poncha Springs.

The SLV Subcommittee of the Colorado Coordinated Planning Group evaluated options to increase reliability and export capacity both within the valley (Phase 1) and from the valley to the Front Range (Phase 2). The subcommittee determined that a new, second 230kV line would alleviate reliability concerns within the valley, eliminate the need for load shedding, and increase export capacity out of the valley significantly: up to 607-MW transmission transfer capacity. However, this new export capacity would then be limited to 252 MW by the substation for Xcel's 115kV line from Poncha Springs going east. Moderate upgrades to this substation would bring the export limit up to 426 MW, with the limiting element being Xcel's other 115kV line going north from Poncha to Malta and Leadville. For reference, the lower export limit (252 MW) corresponds to about 320 MW of new generation (presumably solar) within the valley, while the upper limit (426 MW) corresponds to about 500 MW of new generation. Increasing the export capacity above 426 MW would require new lines from Poncha Springs to either Pueblo or Leadville, which the SLV Subcommittee estimated would be even more expensive than the in-valley line due to the new permitting required and the mountainous terrain (SLV Subcommittee 2016; 2017).

Currently, the new 230kV line within the valley is only conceptual and the project is not moving forward. However, the SLV Subcommittee is planning to reconvene in 2022 to reevaluate this line or explore alternative, lower-cost options to meet the reliability standards for the valley and to (possibly) increase its export capacity. Should the committee and transmission companies decide to pursue the new 230kV line, the project would then go through the siting, permitting, and review process. This process typically involves numerous stakeholders, including state and local governments, federal agencies and tribes (as applicable), and the public (which may include impacted landowners and nongovernmental organizations). Once siting, engineering, and environmental reviews commence, the project developers would file a CPCN application with the Colorado Public Utilities Commission. A CPCN was previously granted by the CPUC for the 230kV San Luis Valley-Calumet-Comanche project that was ultimately abandoned (Appendix A). Additional permitting and easements would also be required, including from local

landowners and federal agencies (e.g., BLM). Figure 3 shows a typical timeline for a transmission project.



Tri-State 2013.

Figure 3. Typical timeline for a transmission project comparable to upgrade considered

4 Project Economics

Even if demand exists and transmission were sufficient, solar developers still might have little interest in a SEZ if they had economically superior alternatives elsewhere. Factors affecting economic competitiveness of a SEZ project include the utility's wholesale cost of power, the expected cost of a solar project in a SEZ, and site factors that make development in a SEZ easier or more difficult than development on nearby private land.

Table 6 shows the recent history of wholesale power costs for Colorado's two investor-owned utilities (Xcel and Black Hills Energy) and for Tri-State, which supplies wholesale power to distribution cooperatives. The averages shown in the table include fuel and other variable costs of generating power from the utilities' own plants, as well as the cost of power purchased from other suppliers.

Table 6. Colorado Utilities' Wholesale Cost of Power, 2017–2021 (nominal $/MWh)

	2017	2018	2019	2020	2021
Xcel	49	55	56	48	57
Black Hills	60	59	58	62	89
Tri-State	Not available		57	55	58

Source: FERC Form 1 reports for 2018 through 2022 for Public Service Company of Colorado (Xcel Energy), Black Hills Colorado Electric, and Tri-State Generation and Transmission Association. Figures shown are total power production expenses (page 320, line 80) divided by total energy sold to retail customers (page 304, line 43), including the cost of purchased power. For Tri-State, figures shown are total power production expenses divided by energy delivered to distribution cooperatives (page 310, line 15).

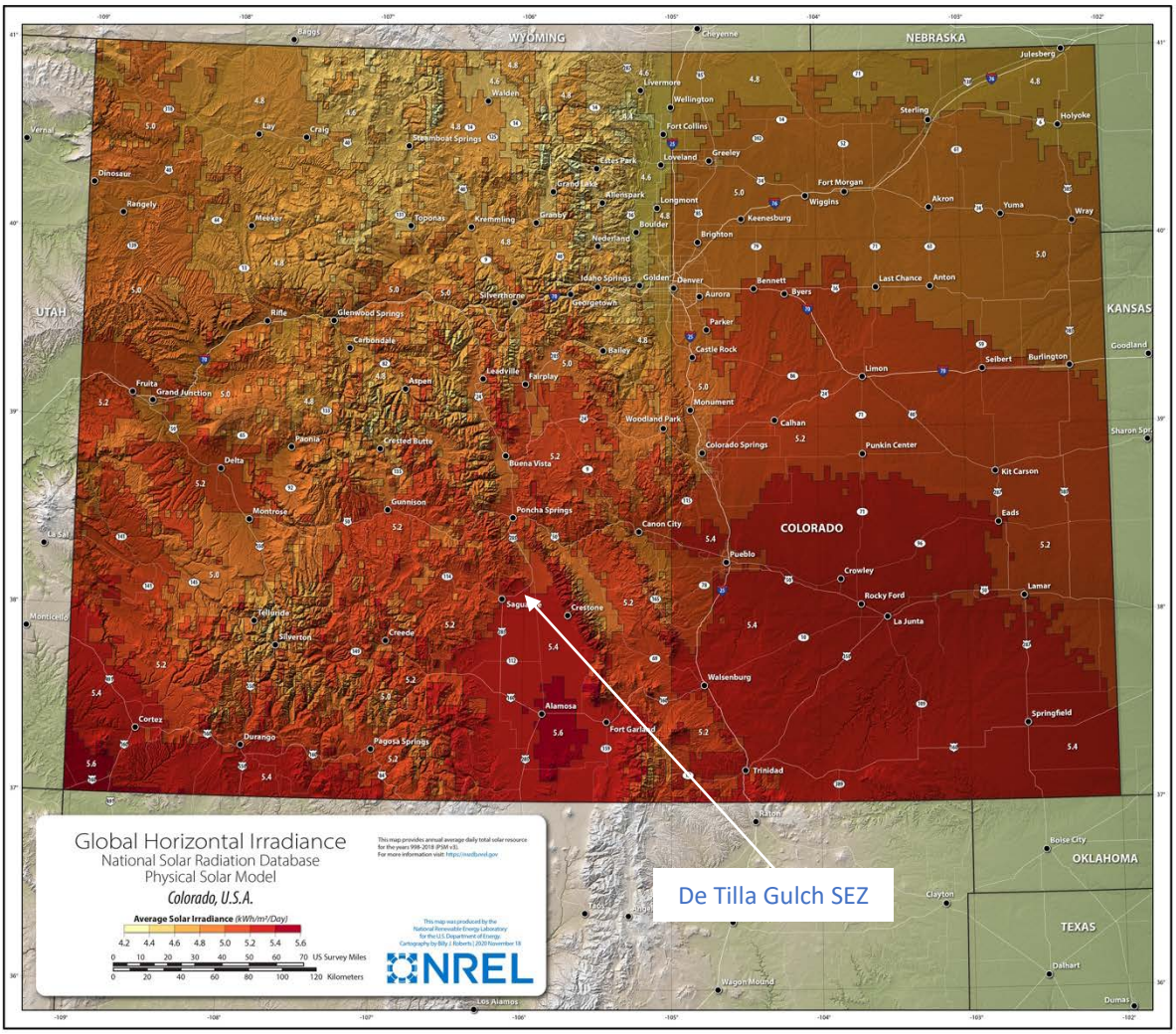
An 80% increase in the cost of fuel for generation (mostly coal and natural gas) helped push Xcel's wholesale power costs to $57/MWh in 2021. Black Hills, whose costs are generally higher than Xcel's, experienced a similar increase. The cost drivers included an increase in natural gas prices (which averaged $3.89/million Btu nationally in 2021 and $2.03/million Btu in 2020) and increased electricity demand after the easing of restrictions related to the Covid pandemic.

The cost of solar power in the valley compares favorably to utilities' current and recent historical costs. We simulated the cost of a hypothetical solar plant in the De Tilla Gulch SEZ, using current equipment costs and the best available data on the solar resource at the site. The analysis indicated that a typical solar plant would likely cost between $36/MWh and $46/MWh. Comparing these results to the utilities' cost of power, while holding all other factors constant, suggests that adding solar power from the valley would reduce overall costs. (See Appendix B for a detailed description of the assumptions used in the simulation.)

In addition, the cost of energy from a solar plant is less volatile than the cost of natural gas. Because a solar plant has no fuel inputs, its all-in cost is largely the annualized finance cost of project development (plus a rate of return) divided by the amount of energy the project is expected to generate over a typical year. A solar project deal often includes an annual escalation factor to account for the project's loss of efficiency over time, but these adjustments are gradual. The volatility of operating costs is much different for a generator using natural gas—fuel costs fluctuate quickly.

The quality of solar exposure is measured as a function of unobstructed sunlight falling on a square meter of land during the year, in direct normal irradiance (DNI) and global horizontal irradiance (GHI).[8] Both measures in the San Luis Valley SEZs are good but not exceptionally better than what may be found in other parts the state.

The map in Figure 4 shows GHI across Colorado. The De Tilla Gulch SEZ, which is indicated on the map, has a GHI of 5.26 kWh/m^2/day. However, a large part of southeastern Colorado has GHI values between 5.2 and 5.4 kWh/m^2/day. This is roughly the same as De Tilla Gulch, meaning the same plant built in southeastern Colorado could produce the same amount energy for every megawatt of capacity.



Source: National Renewable Energy Laboratory's National Solar Radiation Database

Figure 4. GHI for De Tilla Gulch SEZ compared to other Colorado areas

[8] DNI measures the amount of solar radiation from the direction of the sun. GHI measures the combination of direct and diffuse radiation from the sun.

Therefore, though the cost of San Luis Valley solar might compare favorably with utilities' average cost of power, other parts of the state could perform just as well or better. If factors like transmission access are less of an obstacle elsewhere, developers will prefer sites where grid interconnection is easier and less restricted. In 2021, Xcel filed for approval to build a $1.7 billion transmission expansion plan in eastern Colorado called the Colorado Power Pathway, which will be accessible to potential solar development sites east of Pueblo.

Local factors might also affect developer interest in a SEZ especially if transmission access limits what can be delivered to the market. One factor particularly relevant to the valley is a private landowner's choice to convert farmland to solar development. Such sites are already disturbed, already flat, and can often be leased quicker and easier than federal land which is more pristine. If the market is limited by transmission access, private landowners tend to be first in line for developers looking for project opportunities because fewer permitting hurdles are involved.

5 Findings

This market assessment provides some insight into the commercial need for SEZs in the valley. We offer the following observations based on the findings of our analysis.

1. Load-serving utilities in Colorado anticipate future demand for more renewable resources, and the expected cost of new solar projects sited in the valley is less than the utilities' current cost of electricity.
2. Transmission continues to be the biggest obstacle to additional solar development in the valley. As of this writing, however, the valley's transmission-owning utilities have filed no proposal to upgrade the lines that connect the valley with the rest of the Colorado grid.
3. The transmission utilities have studied upgrades to improve the reliability of service to retail customers in the valley. While these upgrades would significantly increase export capacity out of the valley, the main consideration for the upgrades is reliability and not increased renewable energy development. Utilities routinely compare transmission upgrades with non-wires alternatives when evaluating how to manage reliability in a cost-effective manner.
4. Solar exposure as measured by GHI is about the same in the San Luis Valley SEZ as it is east of the Front Range in southeastern Colorado. This implies that a solar plant built in southeastern Colorado could produce just as much electricity per megawatt of capacity as could the same plant built in San Luis Valley SEZ.
5. Transmission limits the ability to move power out of southeastern Colorado, as is the case in the valley. However, Xcel has filed an application to add transmission in eastern Colorado that would enable more solar and wind development.

In summary, the market demand for a solar project built in a San Luis Valley SEZ is, at this time, uncertain. Many alternatives exist in Colorado that can serve the same demand at the same cost but with fewer transmission limitations. The game-changing factor would be a decision by Xcel and Tri-State to upgrade the 230kV line from the valley to Poncha Springs, which would add as much as 600 MW of new export capacity, or four times the solar capacity currently in the valley.

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Appendix A. The San Luis Valley-Calumet-Comanche Transmission Project

In 2009, Xcel Energy and Tri-State Generation and Transmission Association proposed a 140-mile, $180 million transmission line from the San Luis Valley to Walsenburg to upgrade service and transmit solar power from the valley (Wolf 2010). The line would have added up to 700 MW of export capability from the valley.

The proposed route ran through the 171,400-acre Trinchera Ranch in Costilla County, which Texas-based conservationist and hedge fund owner Louis Bacon bought from the Forbes family in November 2007 (Hooper 2007; Blevins 2010). The utilities planned to have the lines ready for service by 2013. Bacon opposed the line, saying utilities had miscalculated the proposed line's structure and effectiveness and were ignoring another route that would provide more power for a cheaper price (Wolf 2010). An Xcel Energy spokesperson told 9News in Denver that the debate over the power line was affecting solar developers' ability to finance projects in the valley (Wolf 2010). In February 2011, the Colorado Public Utilities Commission ruled the line could be built (Raabe 2011), but 9 months later, Xcel announced it was pulling out of the project due to "lower electricity load forecasts, low natural gas prices, lack of federal carbon regulation, expiring tax credits, potential future litigation and a continued sluggish economy" (Williams 2011). Tri-State continued to study alternative options into 2013 to address reliability needs in the region (Williams 2011; Transmission Hub 2018).

A.1 CPCN Application

On May 14, 2009, Public Service Company of Colorado (Xcel) and Tri-State Generation and Transmission Association, Inc., (Tri-State) filed individual certificate of public convenience and necessity (CPCN) applications[9] for the San Luis Valley-Calumet-Comanche Transmission Project (Tri-State CPCN Application; Xcel CPCN Application). A utility must obtain a CPCN from the CPUC before it can begin new construction of transmission facilities or construction of an extension to an existing transmission facility (Colo. Code Regs. § 723-3-3206(a)). A CPCN application must include a statement of facts "relied upon by the applying utility to show that the public convenience and necessity require the granting of the application" and information on each alternative studied, such as general information, costs, and criteria used to compare and eliminate alternatives (Colo. Code Regs. § 723-3-3102(b)).

The project included four components:

- **San Luis Valley–Calumet Transmission Section:** 95 miles, double circuit 230kV line, San Luis Valley substation) to new Calumet substation (Tri-State responsibility)
- **Calumet–Walsenburg Transmission Section:** 6 miles, double circuit 230kV line, new Calumet substation to existing Walsenburg (Tri-State responsibility)
- **Calumet–Comanche Transmission Section:** 45 miles, double circuit 345kV line, new Calumet substation to existing Comanche substation (near Pueblo) (Xcel responsibility)

[9] The Xcel application was Proceeding No. 09A-325E and the Tri-State application was Proceeding No. 09A-324E. The latter became the primary docket after the two were consolidated by the administrative law judge into one docket.

- **Calumet Substation:** new substation 6 miles north of existing Walsenburg substation, which could not be expanded any further due to land and other constraints (Xcel responsibility).

On June 12, 2009, Trinchera Ranch filed a Petition to Intervene and a Request for a Hearing, contesting the CPCN applications (Petition to Intervene). Trinchera Ranch opposed the San Luis Valley-Calumet section of the project, arguing the utilities had not established a need for the project and had not adequately evaluated alternatives. Project supporters favored the increase of electric reliability in the valley and the economic potential of renewable energy development. Supporters also called attention to the need for looped service and the need for transmission to support economic development in and export of renewable energy out of the region as well as the adverse economic impact of valley electricity outages on local famers. Opposition to the project centered on

- the project's proposed route, specifically near La Veta Pass (the Southern Route);
- the potential adverse impacts to the environment, animal habitat, visual resources, and land values; and
- concerns related to adverse health effects from electromagnetic fields and transmission line-related noise (Final Decision 2010).

Several days before an evidentiary hearing, Trinchera Ranch asked to dismiss the proceedings due to multiple ex parte communications between the three CPUC commissioners and the utilities about issues related to the proceeding (Xcel and Tri-State). The motion to dismiss also asked the commissioners to recuse themselves from this proceeding (Final Decision 2010). Trinchera Ranch alleged these discussions included topics such as the CPUC's prior rulings about Senate Bill 100, the CPCN process generally, and the establishment of need for a CPCN (January 25, 2010). One commissioner recused himself from the proceeding, but the chairman and another commissioner did not (Decision No. C10-0124). The remaining two commissioners reviewed the motion to dismiss and denied it (Decision No. C10-1025).

On March 22, 2010, Governor Ritter signed an amendment to Colorado's renewable energy standard that would go into effect August 11, 2010. The amendment had the potential to affect the project's need, so the administrative law judges (ALJs) reopened the evidentiary record and scheduled another hearing for July 26 and 30, 2010, so parties could address impacts. During the hearing, Trinchera Ranch asked to pause this docket until issues in a separate docket regarding Xcel's application to amend its 2007 Colorado Resource Plan had been resolved. The ALJ denied that motion (Final Decision 2010). A month later, Trinchera Ranch asked the ALJ to reopen the evidentiary record to accept testimony on an expansion plan Xcel filed in another docket (the Clean Air Clean Jobs Act docket). Trinchera Ranch asserted that Xcel's testimony in the current proceeding regarding its future plans to export solar-generated electricity from the valley was inconsistent with testimony and the expansion plan it provided in the Clean Air Clean Jobs Act docket. Additionally, Trinchera Ranch argued Xcel failed to supply the expansion plan in response to several of Trinchera Ranch's discovery requests prior to the evidentiary hearing and asked the ALJ to permit limited discovery. Xcel opposed the motion, arguing its Clean Air Clean Jobs Act docket testimony and expansion plan were neither inconsistent with the testimony in the current proceeding nor relevant to the current proceeding. Xcel also argued

Trinchera Ranch failed to cite any authority for its claim regarding the discovery requests. Tri-State supported Xcel's position and raised the practical concern that "it will always be possible for some party to make the argument that a decision on a particular issue in one docket will have a bearing on an issue in another docket." Tri-State asked the ALJ to deny Trinchera Ranch's motion based on the "eminently practical reason, simply put -- when will it end?" Tri-State argued there is "virtually never" a time when all issues in all dockets affecting Xcel would be resolved, and waiting for such an "improbable, if not impossible" time to occur would "hamstring" both Xcel and the CPUC. The ALJ and denied Trinchera Ranch's motion, stating that "there must be an end to this litigation" (Final Decision 2010).

On November 19, 2010, the ALJ issued a recommended decision[10] granting CPCNs to both Tri-State and Xcel to construct and operate the project. One condition included in the CPCN (later referred to as the 700-MW condition) would remain a point of contention into the following year. The condition required that, within 10 years of the project going into service, at least 700 MW of generation (renewable or not) from Energy Resource Zone 4 or Energy Resource Zone 5 must be interconnected with the project. If not, Xcel would have to file with the CPUC a plan to provide ratepayers a 50% refund on the money collected from them for the project (Final Decision 2010).

A.2 Post-CPCN Approval Filings

Three days after the recommended decision was filed, Trinchera Ranch asked to extend the deadlines to file exceptions to the decision and responses to any exceptions as well as the page limit (November 22, 2010 motion). The CPUC extended the deadline, though not for as long as Trinchera Ranch asked, and increased the page limit by 20 pages (Decision No. C10-1295).

On November 24, Trinchera Ranch submitted a Colorado Open Records Act request to the CPUC director for the production of all documents that discussed or were in any way related to the project, future or current plans to develop transmission or generation resources in the valley, and any communications or documents related to any of these topics sent between the CPUC and any other party to the proceeding. After a series of letters and phone calls between November 24 and December 13, Trinchera Ranch informed the CPUC it planned to file an application with the district court because the CPUC did not fulfill the request. After the CPUC provided some of the requested documents in mid-January, Trinchera Ranch expressed concern that some of the requested documents could have been deleted because the CPUC failed to circulate a prompt preservation notice to staff.

In mid-December, Trinchera Ranch filed the first of what would amount to four separate motions in 7 months to reopen the consolidated docket and permit limited discovery. Trinchera Ranch argued that state renewable energy standard statute amendments and resulting amendments to Xcel's Colorado Resource Plan indicated a change in the project's need (December 16, 2010 motion). In the meantime, parties submitted their exceptions to the CPCN decision and presented legal and policy arguments regarding the 700-MW condition imposed by the ALJ. The ALJ addressed the exceptions and several of Trinchera Ranch's motions in a single decision issued on March 23, 2011. The CPUC denied Trinchera Ranch's motion to reopen the record, denied its motion to stay a ruling on the exceptions until the CPUC answered the Colorado Open Records

[10] Recommended decisions become the CPUC's decision after 20 days unless a party files an exception to the recommended decision or the CPUC orders a stay of the recommended decision (4 Colo. Code Regs. 723-1(1505)).

Act request, and granted and denied in parts the utilities' motions to strike certain references in Trinchera Ranch's response to exceptions. Finally, the CPUC disagreed with Trinchera Ranch's argument that such a condition was necessary for consumer protection and noted that such a condition would have implications for both the utilities' ability to raise capital for the project and the future competitive market for renewable energy in Colorado. The CPUC stated that nobody could guarantee the proposed line would be used as expected, that asking the utilities to fully absorb that risk would be unfair. The CPUC concluded that evidence in the record supported the project's need and noted that the CPUC maintains authority to examine the utilities' care in planning, constructing, and operating the project (Decision No. C11-0288, March 2011).

On April 12, 2011, Trinchera Ranch asked the CPUC to reconsider its March 2011 decision, arguing that removing the 700-MW condition was contrary to public policy, arbitrary and capricious, and not in accordance with the evidence (April 12 Application for Rehearing, Reargument, or Reconsideration). After granting the motion on a procedural technicality,[11] the CPUC denied most of the arguments, and only agreed to remove some of the language in the March 2011 decision as dicta (September 13, 2011 decision).

On November 1, the ALJ announced it would not be considering the merits of the motion because Trinchera Ranch had filed its amended application for *writ of certiorari* (review) with the District Court of Costilla County on October 12 (asking the district court to overturn the CPUC's approval of the project), thus removing the ALJ's jurisdiction over the matter while judicial review proceedings were underway in a district court (October 3 Motion for Clarification; November 1, 2011 order; AP 2011). Around the same time, Xcel announced it was pulling out of the project due to "lower electricity load forecasts, low natural gas prices, lack of federal carbon regulation, expiring tax credits, potential future litigation and a continued sluggish economy," generally citing those factors and also keeping costs low for customers (Williams 2011). Xcel had originally predicted the state would need 2,000 MW of additional power, but its 2011 strategic plan reported a significantly reduced forecast of 292 MW. Tri-State continued to study alternative options into 2013 to address reliability needs in the region (Williams 2011; Transmission Hub 2018). The proceeding was formally closed in the docket on January 20, 2016 (Minute Entry January 20, 2016).

[11] A recusal and a resignation in the CPUC led to a lack of quorum needed to legally consider the application before the statutory deadline (May 11, 2011 decision).

Appendix B. Assumptions Used in Hypothetical Solar Project Economic Analysis

The following inputs were used to model a hypothetical 100-MW_{DC}, 700-acre, single-axis tracking photovoltaic system at the De Tilla Gulch Solar Energy Zone (SEZ) leased by the Bureau of Land Management. (This SEZ is the closest to a 230 kV transmission line.) The National Renewable Energy Laboratory's System Advisor Model (SAM) version 2020.11.29r1 was used for the analysis.[12]

B.1 Resource, Equipment, and System Costs

- **Coordinates:** 38.13° N, -106.02° E, elevation 2404 m
- **Solar Irradiance:** Weather file from the National Solar Radiation Database's Typical Meteorological Year[13] at the above coordinates, which indicates a multiyear mean direct normal irradiance (DNI) of 6.89 kWh/m^2/day and global horizontal irradiance (GHI) of 5.26 kWh/m^2/day.
- **Module:** A premium, crystalline-silicon module was selected with the default nominal efficiency of 20.1%.
- **Inverter:** A high efficiency, California Energy Commission 2018-listed, central inverter was modeled with a California Energy Commission weighted efficiency of 98.8%.
- **DC to AC Ratio:** 1.3 (Feldman and Margolis 2018, p. 28)
- **Annual Degradation:** The SAM default of 0.5%/year was used.
- **Total Installed Costs:** A range of expected costs for 2020 from Bolinger et al. (2021) were used: \$0.85/W_{DC} (20th percentile) – \$1.25/W_{DC} (80th percentile)
- **O&M Cost:** The 2020 mean O&M from Berkeley Lab's "Utility-Scale Solar, 2021 Edition"**Error! Bookmark not defined.** was \$15.8/kW_{AC}-year.
- **Internal Rate of Return:** The target was adjusted from the SAM default of 11% to 8%.[14] Internal rate of return target year default of year 20 default was adjusted to year 25.

B.2 Taxes

- The default SAM sales tax rate 5% was used.
- The federal income tax was adjusted from the SAM default of 35% to 21% to reflect the new tax legislation.[15]
- A state income tax SAM default of 7% was used.

B.3 Financial Parameters

- The insurance rate (annual) was dropped from the 0.5% of installed cost default to 0.1% (National Renewable Energy Laboratory et al. 2018).[16]
- Power purchase agreements price escalation was adjusted to 0%. The default analysis period of 25 years was kept.

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[12] "System Advisor Model (SAM)," NREL, https://sam.nrel.gov/.
[13] "NSRDB Data Viewer," NREL, https://maps.nrel.gov/nsrdb-viewer.
[14] Based on ranges from Feldman and Schwabe (2017) and GTM (2017).
[15] "2018 Fiscal-year Blended Tax Rates for Corporations: Notice 2018-38," IRS, https://www.irs.gov/pub/irs-drop/n-18-38.pdf.
[16] A rate of \$0.001 * total insurable value (reported value of physical assets + annual business income) is offered as a cost benchmark (personal communication with David Walter, Senior Engineer, Renewable Energy, The Hartford Steam Boiler Inspection and Insurance Company, June 7, 2016),

- The net salvage value was adjusted from the default of 0% to 10% of installed cost to reflect the value of the facility and generation "tail" after the 25-year project term when electricity could be sold onto the market as well as the salvage value of materials such as aluminum and steel.
- **Project Term Debt:** The default debt service coverage ratio of 1.3 was changed to 1.25 (Feldman and Schwabe 2017); the default tenor of 18 years was changed to 23 years assuming refinancing of the loan during the power purchase agreements term; the annual interest rate default of 7% was adjusted to 3.5% (Feldman and Schwabe 2017, p. 3); and the up-front fee was adjusted from 2.75% of total debt to 1.5%. Debt closing costs were assumed to be covered in the cost of acquiring financing, and this line item was left at $0.
- The cost of acquiring financing was adjusted from the default of $0 to $1,000,000 (Feldman and Schwabe 2017, p 3).
- The construction period debt was adjusted to reflect one loan for 75% of installed costs.
- **Reserve Accounts:** Interest on reserves was changed to 1.5%/year, with the working capital reserve of 6 months lowered to 3 months of operating costs. The same adjustment was made to the debt service reserve account to reflect 3 months of principal and interest payments.
- A replacement reserve account cost of $0.05/W with a frequency of 12 years was included to reflect the cost of inverter replacement.
- The model used assumed the 26% federal investment tax credit.[17]
- A 5-year modified accelerated cost recovery system cost recovery period was applied to qualifying solar energy equipment.[18] Bonus depreciation was not included.

[17] "Solar Investment Tax Credit (ITC)," Solar Energy Industries Association, https://www.seia.org/initiatives/solar-investment-tax-credit-itc.
[18] "Publication 946 (2021), How To Depreciate Property," IRS, https://www.irs.gov/publications/p946/ch04.html.