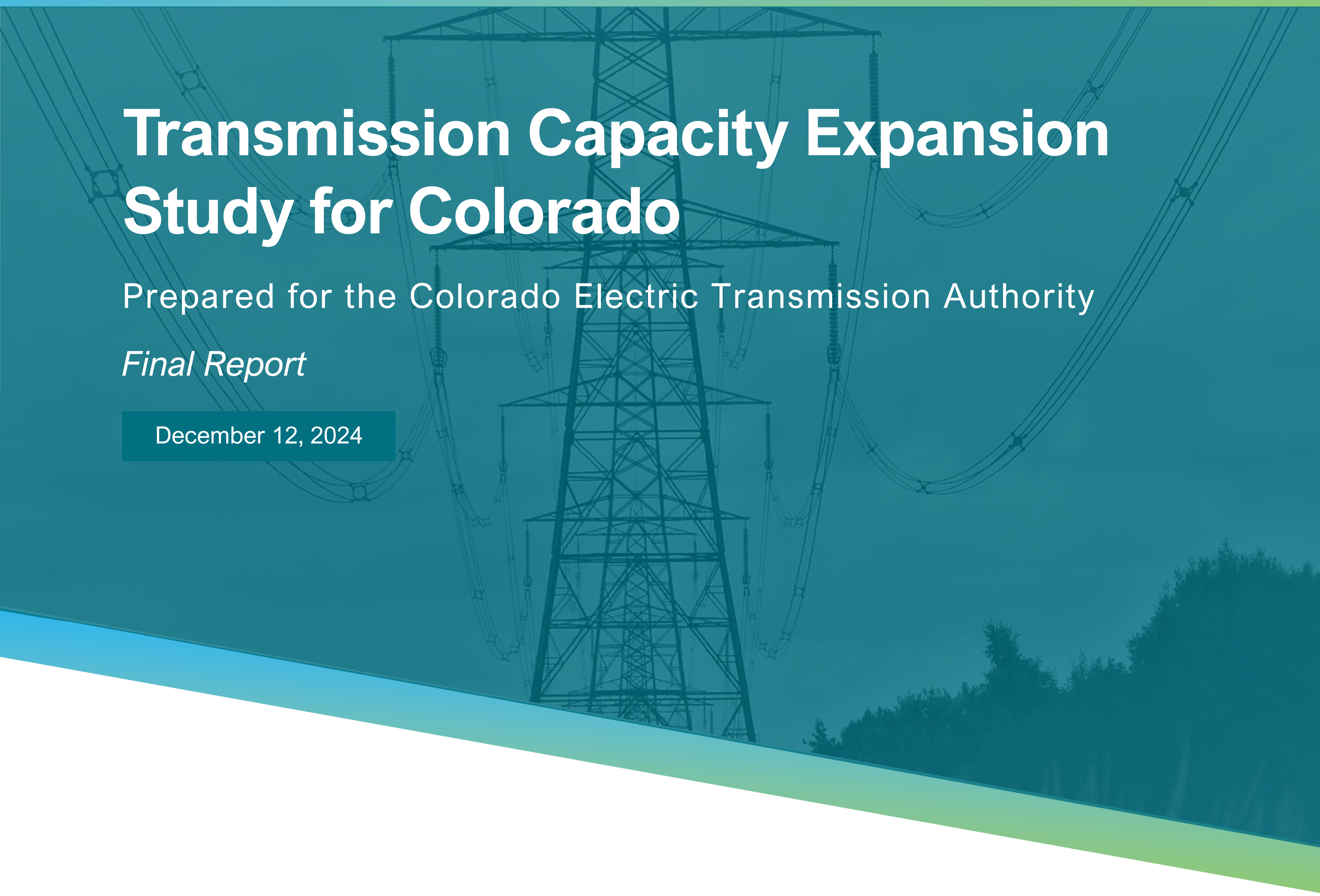

Transmission Capacity Expansion Study for Colorado

Prepared for the Colorado Electric Transmission Authority

Final Report

December 12, 2024

ENERGY STRATEGIES

COLORADO ELECTRIC TRANSMISSION AUTHORITY

Purpose of this Final Report

This report summarizes the findings of the Colorado Electric Transmission Authority (CETA) Transmission Capacity Expansion Study, which was commissioned in response to Senate Bill 23-016 and offers a holistic analysis of Colorado's transmission system. The purpose of the study was to assess the need for transmission capacity to meet Colorado's growing electricity demand, clean energy and emissions reduction targets, while ensuring reliability and efficient flow of power on the state's electric grid. Key objectives of the study include identifying gaps in transmission infrastructure, identifying potential transmission upgrades, and exploring solutions for improving power flows within Colorado and across interstate connections. Benefiting from independent analysis and input from a broad set of stakeholders, this study exploring Colorado's transmission needs serves as a roadmap for decision-makers, utilities, and stakeholders working to align the state's infrastructure development with policy objectives and the need for reliable and efficient power supply.

This Final Report is released after the Initial Report published on October 7, 2024. Seventeen stakeholders submitted comments on the Initial Report. This Final Report summarizes stakeholder guidance regarding CETA's prioritization of identified transmission projects, adds information collected from stakeholders on their transmission development pursuits and recommended future studies, while adding clarifications and additional detail regarding study assumptions and interpretation of results.

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The Project Team would like to thank the CETA Board of Directors, listed below, and its Executive Director Maury Galbraith for the opportunity to perform this first of its kind study in Colorado. In addition, the team would like to recognize the substantive and valuable insight offered by the stakeholders that participated in the study webinars and provided input verbally and through written comments.

Disclaimers

This work product utilizes information obtained from publicly available sources and, in some cases, has relied upon subscription data and other third-party information available to Energy Strategies. While these sources are considered reliable, Energy Strategies does not recommend that the information contained herein be the sole source of information for decision-making purposes. Users of this report are encouraged to seek additional sources and professional advice before making any decisions based on the information provided in this study.

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1. Study Objectives, Methodology, and Stakeholder Engagement

In 2023, the State of Colorado, through Senate Bill 23-016, directed the Colorado Electric Transmission Authority (CETA) to conduct a study assessing the need for expanded transmission capacity in the state. The act responds to the state's growing electricity demand, the need to meet Colorado's emissions reduction goals, and the importance of improving power flows and overall grid reliability. Colorado has policy goals to reduce greenhouse gas emissions, aiming for a 50% reduction by 2030 and net-zero emissions by 2050. Achieving these goals in a reliable and cost-effective manner is anticipated to require substantial expansion and improvement of the state's transmission infrastructure, which is critical for interconnecting new generation and efficiently moving power from where power is generated to where it is consumed.

In response to SB23-016, CETA launched a Request for Proposals (RFP) and selected Energy Strategies and a team of subcontractors to conduct this Transmission Capacity Expansion Study (referred to as "study" throughout). The study takes a long-term, holistic approach to evaluating transmission needed to support Colorado's reliable transition to a clean energy future.

Study Objectives

The goal of the study was to explore Colorado's long-term need for transmission capacity based on a holistic study approach, focusing on new planning issues not addressed in other planning processes such as those performed at the regional or local (e.g., utility) level. Primarily a 20-year planning assessment, the study considered broad drivers of transmission – demand, policy, economics (production cost modeling congestion and costs), and reliability – with the goal of providing CETA insight into transmission planning "gaps" that may exist and assessing the ability of new transmission solutions to fill such gaps. In addition to considering Colorado utility plans for transmission construction over the approaching 10-years, the study factored in forecasted resource additions from Colorado Electric Resource Plans (ERPs), accounted for the effects of developing energy markets, considered a range of planning scenarios and transmission technologies, and featured a state-wide generation forecast for the 20-year time horizon.

The underlying objectives of the work, informing the design of the study, was to forecast transmission additions that would:

- Help meet the forecasted demand for electricity,
- Achieve the state's emission reduction goals,
- Improve power flows on the transmission system, and
- Enhance grid reliability.

Given the potential for increases in electricity demand driven by rapid electrification, data center development, and new sectors like hydrogen production, Colorado's grid may face significant strain. Therefore, to keep up with growing demand it is critical to expand grid capacity not only through new transmission lines but also by improving existing infrastructure. This strategy was a focus of this study. Additionally, Colorado's geographic isolation and relative weak interstate ties support the need for stronger interstate connections to enhance market access and improve grid resilience. To help address these and other similar planning challenges, the study accomplished several key tasks:

- **Facilitating a comprehensive stakeholder engagement process**, with a focus on developing and refining modeling input assumptions and selecting scenario analyses.
- **Reviewing, compiling, and summarizing utility and independent developer transmission plans** to provide a source of truth for identifying incremental grid needs above and beyond what is planned.
- **Performing a holistic transmission capacity expansion study**, taking a long-term view of Colorado's future transmission needs over the next 20 years, with a focus on physical versus contractual needs of the system.
- **Conducting a gap analysis** that compares transmission projects included in utility and developer plans against the needs identified in the study, providing information that CETA and the state can use to help ensure the Colorado grid will be capable of supporting the state's clean energy transition, accommodating rising electricity demand, and servicing reliability for decades to come.

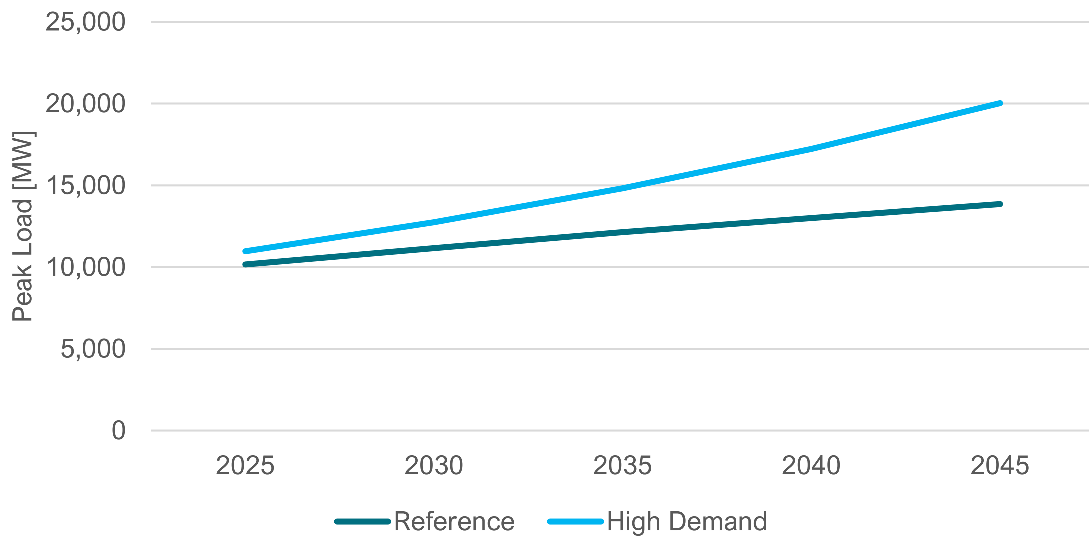
Summary of Study Methodology

The study followed a multi-step methodology that included reviewing utility and independent transmission plans, performing a holistic 10- and 20-year transmission capacity expansion analysis, and conducting a detailed transmission gap analysis. Central to this effort was active stakeholder engagement, ensuring that input from utilities, developers, and public agencies was integrated into the modeling scenarios and proposed solutions.

1. Develop Load and Resource Trajectories

The transmission assessment was based on a "Reference Case" that represented a "status quo" trajectory of the Colorado grid in two study years: 2035 and 2045. One of the critical inputs to the study was a forecast of load growth over a 20-year horizon. Informed by data sourced from the National Renewable Energy Laboratory (NREL) and Colorado utility ERPs, the load forecast developed for the study's Reference Case projects Colorado peak demand of about 14 GW by 2045, up from around 10 GW today. The peak demand forecast used for the study's Reference Case (e.g., business as usual) and "High Demand" scenario are below.

Figure 1: Colorado Peak Load Growth Forecast [1]



The forecasted load, among various other forecasts and constraints related to resource costs, reliability requirements, and policy goals, were input into a capacity expansion model called RESOLVE.[2] The tool identifies optimal generation and storage investments using linear programming, adhering to reliability, technical, and policy constraints. Energy Strategies obtained, validated, and updated this model to establish a credible 20-year state-wide resource plan. For this study, RESOLVE captured a baseline resource forecast of existing, planned, and proposed generation from recent Colorado ERPs. It then identified *additional* generation needed after 2035, establishing a resource plan that extends beyond ERP forecasts that was suitable for a 20-year transmission planning horizon. This modeling was crucial in defining the state's future resource needs and guiding subsequent transmission assessment.

As shown below, Colorado ERPs call for 10 GW of new capacity by 2035, with this study forecasting a need for an additional 15 GW of capacity to meet load and policy goals by 2045. Additions for the Reference Case include 7 GW of wind, nearly 3 GW of solar PV, 3 GW of new firm resources, and nearly 2 GW of battery storage.

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[1] Reflects the maximum single-hour load of Colorado customers. Colorado utilities must plan to have generation capacity available to serve this load plus a reserve margin.

[2] RESOLVE, an open-source capacity expansion model, was adapted from the 2021 Colorado GHG Reduction Roadmap developed by Energy & Environmental Economics Inc. (E3) for the Colorado Energy Office.

Figure 2: Colorado Installed Generation Capacity Over Study Horizon by Category

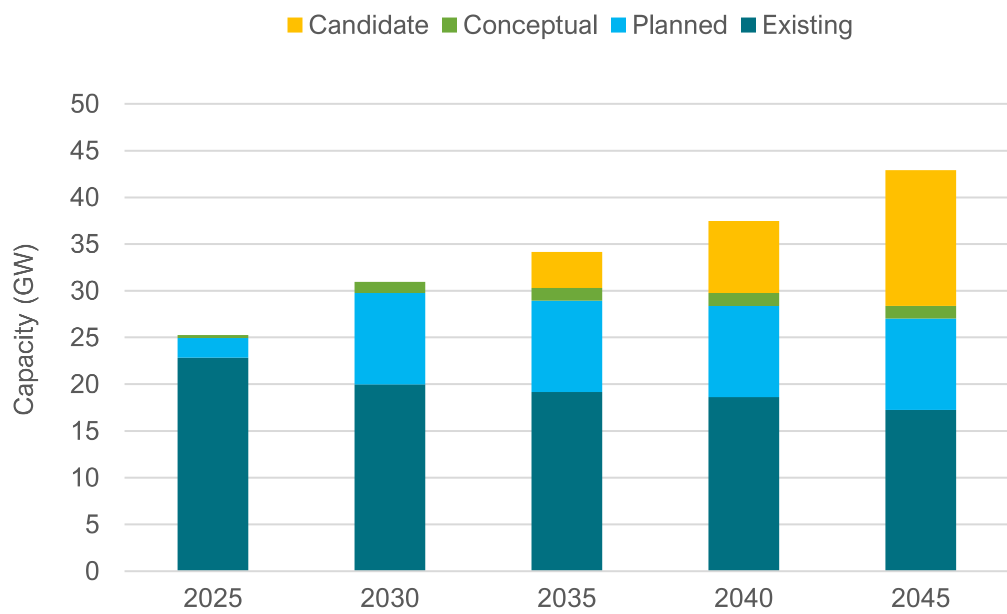
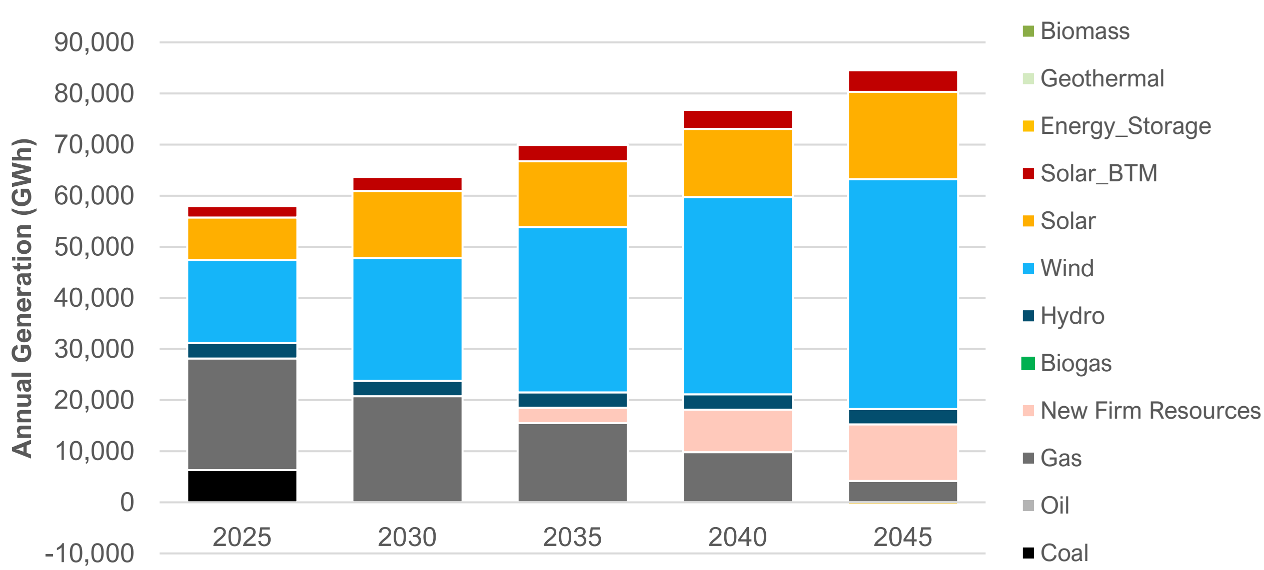


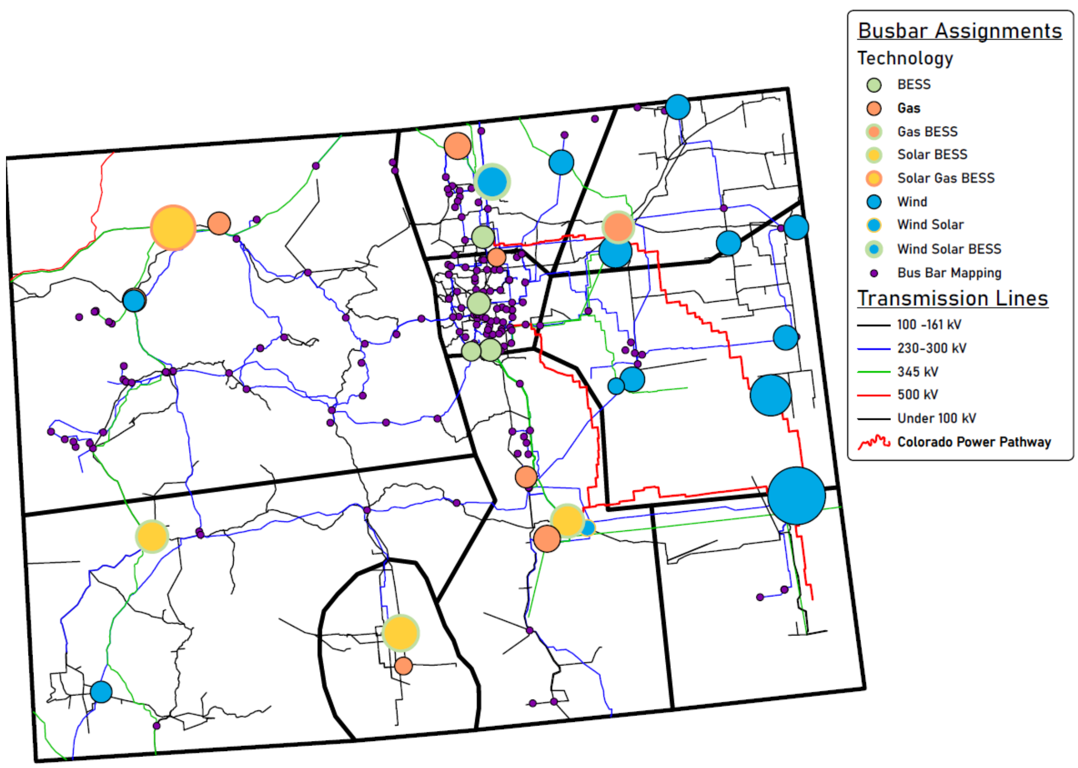
Figure 3: Colorado Resource Mix Over Study Horizon by Generation Type



The state-wide resource buildouts above were allocated first into Colorado's five Energy Resource Zones (ERZs)[3] and then mapped onto busbars (e.g., substations). This so called "busbar mapping" analysis is a critical step in refining the generation expansion portfolios developed through the capacity expansion modeling. While the initial generation portfolios are geographically coarse, busbar mapping addressed the need to locate resources to physical substations. This enabled ensuing transmission analyses to reflect grid impacts caused by future generators. Through this process, the study was able to partially address the "chicken and the egg" planning problem where a lack of information on the location of future generation hampers transmission development (and vice versa).

The busbar mapping process used in this study identified suitable substations based on various factors, including commercial interest, hosting capacity, land constraints, resource quality, engineering preference, and stakeholder feedback. Throughout the process, stakeholder feedback played a crucial role in refining the placement of resources. For example, early plans for high resource deployment in remote areas of Western Colorado were adjusted due to transmission limitations and reduced commercial interest.

Figure 4: 2045 Reference Case Generator Additions and Busbar Mapping



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[3] Colorado Senate Bill 07-100 ("SB07-100") requires Public Service Company of Colorado and Black Hills to designate ERZs which are geographic areas in which transmission constraints hinder the delivery of electricity to Colorado consumers, the development of new electric generation facilities to serve Colorado consumers, or both.

Once completed, the refined substation-level generator placements were integrated into the study's powerflow and production cost models, ensuring consistent and reliable transmission planning across all phases of the study. The process also resulted in increasing the number of study zones from the five SB100 ERZs to nine zones for this study.

Details and additional results regarding this step developing *Load and Resource Trajectories* for the study can be found in Stakeholder Meeting #1, Stakeholder Meeting #2, and Stakeholder Meeting #3.

2. Assess Transmission Needs & Solutions

The first step in assessing Colorado's long-range transmission needs involved a comprehensive review of utility and independent transmission plans across Colorado. This analysis cataloged planned and conceptual transmission projects and identified those which were likely to be in-service within the 10-year horizon. The review laid the foundation for identifying future transmission needs and setting the baseline for transmission expansion gaps that may need to be addressed. Conceptual projects were not assumed to be in-service in the 10-year horizon and were considered as alternatives when identifying options to meet identified transmission needs.

The planned & under construction major upgrades assumed in the study total roughly $2 billion of transmission investment. Some of the most critical of these upgrades are summarized below.[4]

Figure 5: Planned Projects Included in Study

Colorado Power Pathway (PSCO)	ISD
Seg. 1: Ft. St Vrain - Canal Crossing 345 kV	2026
Seg. 2: Canal Crossing - Goose Creek 345 kV	2025
Seg. 3: Goose Creek - May Valley 345 kV	2025
Seg. 4: May Valley – Tundra 345 kV	2027
Seg. 5: Tundra – Harvest Mile 345 kV	2027

Responsible Energy Plan (TSGT)	ISD
Burlington-Lamar 230 kV	2025
Boone-Huckleberry 230 kV	2026
Big Sandy-Badger Creek 230 kV	2028

The modeling effort to evaluate Colorado's transmission needs started with a powerflow assessment, exploring both reliability and deliverability issues. The 20-year powerflow models were updated with the load forecast presented above, planned transmission projects, and resources located per the bus-bar mapping analysis. The assessment explored two grid conditions, exploring broad reliability concerns and the potential for deliverability constraints.

The **reliability study** evaluated system performance based on Reliability Standards set forth by the North American Electric Reliability Corporation (NERC) [5]. The NERC Standards define how the bulk electric transmission network must perform when planning and operating the system. In particular, the

[4] This list of planned projects is not comprehensive and includes only major projects assumed in the 10-year study horizon. Other smaller upgrades were modeled and validated in the case.
[5] https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx

standards known as Transmission Planning Performance (TPL) Requirements establish the criteria for planning and operating over a broad spectrum of conditions. For the reliability study, peak load conditions were simulated, using operationally appropriate generation dispatches to balance supply and demand under stressed scenarios. The entire system was challenged, but no specific area experienced extraordinary stress. Import capacity was limited by physical constraints, and a steady-state contingency analysis was performed to identify transmission areas lacking the necessary capacity to maintain NERC Reliability Standards under stressed conditions. The same line monitoring, contingencies, and reliability criteria used in the 10-year assessment were applied.

The **deliverability study** was developed to study the reliable transfer of resources located in zones with similar electrical characteristics and transmission constraints. Although the reliability analysis primarily focused on a single case, nine zonal cases were developed for specific regions, such as the San Luis Valley (SLV) and Southeast Colorado / Lamar regions. Each zone was studied individually to ensure the local system could reliably transmit generation from the resource zones to load centers during stressed system conditions. This case assumed that basic interconnection requirements for resources were met. The analysis focused primarily on identifying and correcting transmission deficiencies that could lead to congestion or deliverability issues within a resource zone. The study tested whether resources could still be dispatched when resources outside the zone were unavailable, with proposed upgrades also likely to support on-peak deliverability, which was the focus of the reliability study.[6]

In addition to the deliverability and reliability analyses above, a **congestion study** was performed to identify any remaining grid bottlenecks using a nodal economic dispatch model (GridView™). The primary focus was to (1) analyze where congestion could hinder the efficient transfer of electricity, and (2) identify upgrades to alleviate such congestion. The study used nodal production cost modeling to simulate generation dispatch and resulting transmission congestion on in-state and interstate transmission lines, focusing on lines greater than 200-kV. The main criteria for identifying congestion were annual congestion costs and hours of congestion. This phase of the study provided insights into where the grid's economic bottlenecks were most acute, offering a targeted approach to improving the efficiency of the overall transmission network.

The powerflow and congestion studies were performed sequentially and were used to identify transmission needs that were then addressed via a **transmission alternatives** analysis that identified potential transmission solutions. The analysis considered a variety of transmission alternatives, many suggested by stakeholders, including new builds, reconductoring and advanced conductors, rebuilding or co-locating new transmission lines in existing corridors, and other advanced transmission

[6] The deliverability assessment evaluated the performance of individual zones by increasing existing and planned resources to maximum or near maximum levels and dispatching that power to the Denver metro load center and other zones. System performance was monitored for both system intact and contingency conditions, evaluating the ability to reliably deliver power supply. When issues were found, system upgrades were evaluated to determine how they could mitigate the performance issues.

technologies such as dynamic line ratings, powerflow control devices, and storage as a transmission solution.[7]

The general criteria for determining the type of *preliminary* transmission solution were as follows:

- If a transmission line was overloaded such that a reconductor would mitigate the issue, then reconductoring was recommended.
- If a line was overloaded such that a reconductor would not be adequate, then a new line was recommended (but the existing line kept at the existing rating). This was referred to as greenfield, since a new line was needed, in addition to the existing line.
- Finally, if the study showed that a new line was needed, and the existing line also needed to be upgraded, then it was recommended to rebuild the existing transmission line to double-circuit, with both circuits at a higher rating. [8]

The purpose of the process outlined above was to arrive at a preliminary upgrade that could be used to benchmark the performance of alternatives. It was necessary to identify a viable option to mitigate overloads before assessing grid enhancing technologies (GETs), advanced conductors, and other potential solutions as a technical baseline is needed to evaluate the viability of these options. Once a preliminary solution was identified, the study team evaluated the technical viability of a wider range of transmission solutions to attempt to identify the most efficient option. An example of this analysis is summarized in the table below, where we show the results of a review of a set of projects.

[7] Advanced conductors include aluminum conductor, steel supported (ACSS), aluminum conductor composite core (ACCC), and thermoplastic high-heat resistant and water-resistant (TW/THW).
[8] Note that the category assignments are subjective and require substantive engineering judgement. Future work is needed to further refine and finalize the transmission upgrades identified in this study.

Table 1: Sample of Transmission Alternative Review

Viable | Not viable | Potentially viable

Project(s)	Potential Project Alternatives	Reconductor / Advance Conductor	Rebuild/ Co-Locate	Storage	Advance Powerflow	Dynamic Line Ratings
Ft. Lupton-Pawnee 230kV #2 New Ault – Keota 345 kV	Yes. Reconductor Ft.Lupton – JLGreen 230 kV	Yes. Good candidate to double-circuit and have Advance Conductor	Yes. Rebuild existing line to double-circuit	No - transmission needed to ensure reliability	No. Operational tool for narrow powerflow adjustments.	No; Best for operational issues and non-stressed conditions
Wray – N. Yuma 230kV #2	Reconductor Wray - N. Yuma 230kV Line, add Wray transformation	Yes. Good candidate to double-circuit and have Advance Conductor	Yes. Rebuild existing line to double-circuit	No - transmission needed to ensure reliability	No. Operational tool for narrow powerflow adjustments.	No; Best for operational issues and non-stressed conditions
Smoky Hill – Missile Site - Pronghorn 345kV Line #2	Reconductor existing 345 kV line.	Maybe, Reconductoring alone does not solve outage of transmission line	Yes. Rebuild existing line to double-circuit	No. Storage at Smoky Hill could allow temporary relief, but not permanent solution	No. Operational tool for narrow powerflow adjustments.	No. Best for operational issues and non-stressed conditions
New Lamar – May Valley 345kV Line 5 mile / $37.5 M	Lamar – Gladstone 345kV Line 185 miles / $644 M	Maybe –Greenfield	No – Greenfield, but good candidate for more ROW	No - transmission needed to ensure reliability	No. Operational tool for narrow powerflow adjustments.	No. Best for operational issues and non-stressed conditions
Comanche/Huckleberry-Gladstone 230kV Line #2	Reconductor Comanche – Walsenburg – Gladstone 230 kV	Maybe, Reconductoring alone does not solve outage of transmission line	Yes. Rebuild existing line to double-circuit	No. Storage at Smoky Hill could allow temporary relief, but not permanent solution	No. Operational tool for narrow powerflow adjustments.	No. Best for operational issues and non-stressed conditions

As shown in the example, the preliminary upgrades were evaluated against routing alternatives, reconductoring alternatives, advanced conductors, rebuilds, storage as a transmission asset, advanced powerflow controllers, and dynamic line ratings. Of those alternatives that were **technically viable for a given transmission need**, the study team performed a cursory evaluation of cost-effectiveness, efficiency, and land use, and selected the upgrade option that would minimize impact while maximizing system benefit for the lowest cost.

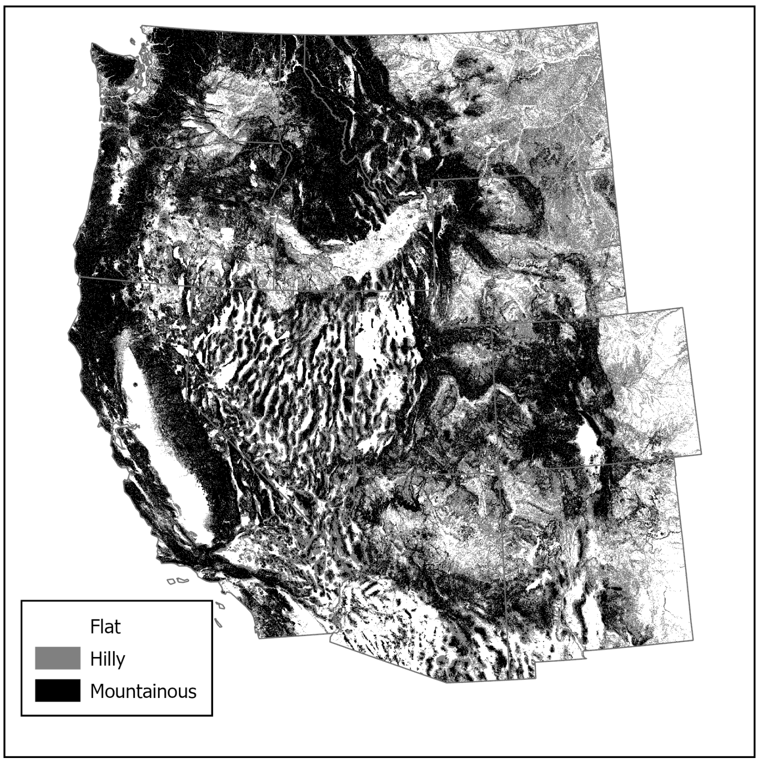
Throughout the transmission solutioning phase, stakeholder input was critical to refining the proposed solutions. Feedback from utilities, developers, and other stakeholders helped ensure that the solutions were both practical and aligned with the broader needs of Colorado's energy system. By the end of the transmission solutioning phase, the study arrived at a portfolio of transmission upgrades, including new transmission lines, reconductoring projects, and advanced technologies. Since the study focused on the 20-year modeling horizon, grid overloads were quite severe and were not mitigated by storage devices, advanced powerflow controllers, and dynamic line ratings. However, this does not mean these technologies are not viable options for deferring upgrades in the near-term or for less severe issues.

For each final transmission solution included in the portfolio, a preliminary cost and right-of-way was identified via an "optimal-cost-path" geospatial routing process. The development of transmission cost estimates in the study involved a detailed and systematic process to ensure planning-level accuracy while also accounting for various geographic and technical factors. Key inputs into this process included:

- **Transmission cost assumptions:** The Midcontinent Independent System Operator (MISO) has developed a cost estimating guide that is one of the standard tools used by transmission planners nationwide. This study utilized per-unit line costs sourced from MISO's most recent cost guide, adapted by Energy Strategies, as a baseline for estimating transmission project costs.[9] Per-unit cost estimates were developed for greenfield lines of all voltages, as well as reconductoring, rebuilds, and other transmission solutions.

- **Terrain multipliers:** Applied during the routing optimization process to ensure that the cost estimates for transmission projects accurately reflected the complexity and difficulty of constructing new lines across Colorado's diverse landscapes. These multipliers adjusted baseline cost estimates (above) to account for factors such as slope, vegetation, water bodies, and fire risk, allowing the study to prioritize routes that were cost-effective while minimizing environmental and construction challenges. [10] For example, areas such as flat terrain with minimal construction challenges were assigned a multiplier of 1.0, while mountainous terrain with a slope greater than 8% received a multiplier of 1.75, reflecting the added cost of transporting equipment, managing environmental impacts, and ensuring stability in these rugged areas.

Figure 6: Terrain Difficulty Contour Used to Inform Line Routing



[9] The MISO Transmission Cost Estimation Guide for MTEP 2024 can be reviewed here: https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf. A summary of this cost data is included in the Appendix.
[10] The cost estimates also incorporated methodologies consistent with industry-standard tools, such as the WECC Transmission Cost Calculator (2019), EPRI-GTC (2006), and additional research sources like Wu et al. (2023).

- **Existing rights-of-way:** Prioritized routes that could co-locate new lines with existing transmission infrastructure to minimize environmental impact and land acquisition costs. By accounting for this transmission expansion option, the study considers options for expanding transmission capacity in the state while minimizing land use impacts.
- **Environmental sensitivities and land use considerations:** Routing away from developed areas, agricultural land, and recreational areas to reduce land-use conflicts and mitigate potential opposition, while also avoiding or minimizing disruption to protected areas, wildlife habitats, wetlands, and other environmentally sensitive regions.

Given the long-term nature of this study, it should be understood that transmission solutions, routings, and cost estimates are all preliminary in nature. The severity of loadings could change, making GETs a more viable solution in some cases, or perhaps mandating the need for more new corridors or greenfield expansion. Similarly, as more detail about the potential routing options for individual lines is uncovered through their development, the ultimate corridors selected could vary substantially from what is identified in this long-range planning study. Finally, transmission build costs are constantly changing and are subject to many cost uncertainties, making the estimates provided in this study useful as a “planning-level” estimate, but not appropriate for forecasting the exact cost of any lines or portfolio of lines.

3. Explore Alternative Scenarios and Concepts

The study’s Reference Case is a single deterministic view of power system developments in Colorado. The inclusion of scenarios in the study was essential for exploring how various future conditions might impact Colorado’s transmission system and the need for new transmission capacity. The scenarios allowed the study to test the robustness of the grid under different assumptions related to electricity demand growth, renewable energy deployment, and regional market integration. By modeling a range of possible futures, the study aimed to identify the most durable transmission solutions capable of supporting Colorado’s electricity customers under a diverse set of outcomes. Scenario analysis also provided a way to assess risks and uncertainties that could affect the state’s transmission needs over the next 20 years.

To ensure that the scenarios reflected realistic and relevant future grid conditions, stakeholder engagement played a crucial role. The study team worked closely with utilities, transmission developers, public agencies, and non-profits to gather feedback on the assumptions and inputs used to build the scenarios. Stakeholders were invited to participate in workshops and review sessions where the proposed scenarios were discussed, refined, and finalized. This collaboration ensured that the scenarios incorporated insights from industry experts engaged in the process.

Several key scenarios were selected based on their ability to capture a wide range of critical transmission challenges in Colorado:

- **Reference Case –** This scenario assumed business-as-usual conditions with moderate load growth and the deployment of resources consistent with existing Electric Resource Plans (ERPs).

It served as a baseline for comparison with other scenarios and is highlighted in the results section as the Reference Case transmission portfolio.

- **High Demand –** Designed to assess the impact of rapid electrification and introduction of new point loads like data centers, electric vehicles, and hydrogen production. It required the expansion of both transmission infrastructure and energy resources to meet the increased demand.

Regional Integration – Explored the implications of greater transmission and market integration between Colorado and the Southwest Power Pool (SPP) footprint. It examined how regional integration between SPP and the eastern edge of Colorado might impact the 20-year portfolio to help the state meet policy objectives. Working from the Reference Case, the study also explored **Conceptual Alternatives** to the Reference Case as well as **three options for inter-state transmission**. These analyses were included in the study to address interest from the study's stakeholders, and to bolster the study's investigation into potential future transmission gaps and opportunities in Colorado.

By testing these scenarios and alternative options, the study provided a comprehensive view of the transmission investments required to ensure grid reliability and support Colorado's energy transition under different potential futures.

4. Perform Transmission Gap Analysis

The final step in the study process – the transmission gap analysis – assesses where Colorado's current and planned transmission infrastructure might fall short in meeting future demands. By comparing existing and planned projects with forecasted needs and solutions identified in the study, the analysis pinpointed areas where the transmission system lacked capacity. This process involved reviewing utility transmission plans, developer proposals, and performing a detailed capacity and reliability assessment over a 20-year horizon via the methods described above. The gap analysis was critical in identifying areas that could require additional capacity to ensure that Colorado's grid could support its clean energy transition and maintain reliability and efficient power flows across different futures.

Stakeholder Engagement

The scope of work for the CETA study identified "active stakeholder engagement" as one of the guiding principles for this work. Energy Strategies hired Gridworks to facilitate this engagement. Gridworks is a non-profit organization that provides stakeholder engagement services, policy advice, and technical assistance to support challenging energy conversations in the West.

The study team held four stakeholder meetings during the first half of 2024. Each of these meetings was noticed on the CETA website and conducted virtually with open access; meeting recordings and materials are posted on the study webpage. The study team also regularly engaged with stakeholders via email and phone throughout the study. Find a list of organizations that participated in the stakeholder work and/or submitted written comments in the Study Appendix.

1. Purpose

The goal of the engagement was to provide many opportunities, early in the process, for stakeholders to shape the analysis and guide study outcomes. Meetings were scheduled at key decision points as the analysis unfolded so that stakeholders could consider alternatives and weigh in. These included discussions of study assumptions, scenario selection, zonal resource allocations, and preliminary results. A summary of meeting topics and stakeholder participation follows in Table 1.

Table 2: Stakeholder Summary

	Meeting #1 Feb. 9, 2024	Meeting #2 Mar. 22, 2024	Busbar Mapping Proposal Apr. 12, 2024	Meeting #3 May 24, 2024	Meeting #4 Jul. 26, 2024
Purpose	Methodology and reference case assumptions; introduced busbar mapping proposal	Reviewed methodology and study progress; proposed study scenarios	Proposed zonal resource allocations and busbar mapping details	Reviewed reliability results and discussed potential solutions	Reviewed production cost modeling results; discussed top expansion opportunities
Stakeholders in Attendance	46	54	N/A	40	51
Organizations Represented	~30	~40	Circulated to ~100 contacts	~30	~48
Written Comments Received	6	7	Informal exchanges	11	Laid over to initial report

2. Stakeholder Comments

Early in the engagement, stakeholder comments focused on better understanding the study methods. Stakeholders asked about study assumptions including load forecasts, renewable capacity accreditations, study footprint, out-of-state generation assumptions, the use of utility resource plans and other planning studies. As the study progressed, stakeholder input evolved into scenario considerations (extreme weather events, electrification assumptions, use of distributed energy resources, seams and market frictions) and then eventually into perspectives on trade-offs (generation mix, use of distributed generation and storage as transmission, criteria for using advanced conductors, interstate connections). The stakeholder feedback informed decisions at each step in the study process.

The study team appreciates the stakeholder collaboration throughout the process and recognizes the time and effort of so many involved to produce the study's robust results. A list of participating organizations is provided in the Appendix.

2. Study Results

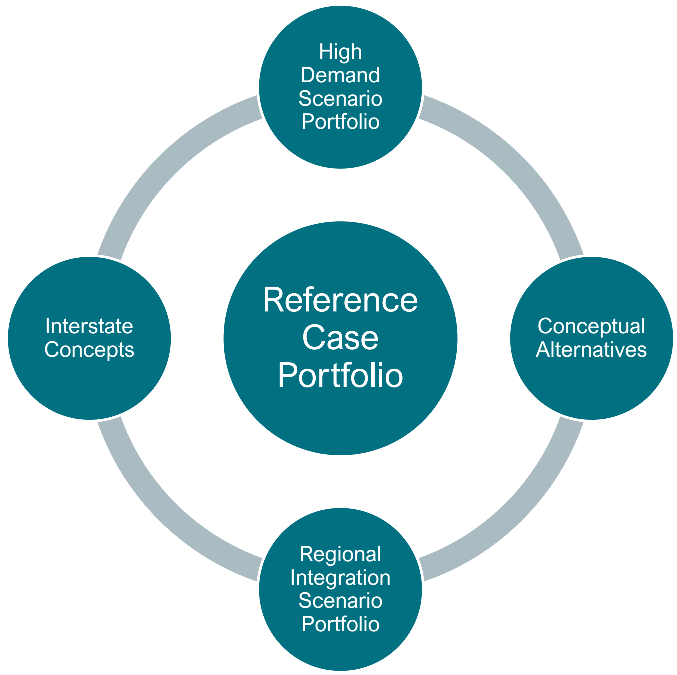
Colorado's transmission needs were evaluated for a variety of future conditions. The **Reference Case Portfolio** was developed based on a "status-quo" view of Colorado's future power system and was the foundation upon which alternative project concepts and scenarios were developed. These additional evaluations included:

- Identifying a list of **Conceptual Alternatives** to transmission solutions identified in the Reference Case Portfolio. These alternatives represent projects that might be needed based on changes in resource deployment in Colorado or are possible alternatives to projects in the Reference Case Portfolio.
- Identifying three **Interstate Transmission Concepts** that may have the potential to increase the capability of moving power into and out of the state.
- Developing the **High Demand Scenario Portfolio** which identified the magnitude of transmission upgrades that would be required in addition to the Reference Case Portfolio to accommodate a 50% increase in projected peak demand growth.
- Developing the **Regional Integration Scenario Portfolio** which identified projects that could enhance the Reference Case Portfolio, assuming a significant portion of the 20-year resource needs were delivered from the Southwest Power Pool (SPP), across the eastern edge of Colorado.

The transmission gap analysis compared known transmission projects plans with the projects identified in the various portfolios above. As a first step, the study team reviewed utility and developer plans to not only ensure that they were included in models, but to also confirm that any identified needs would be in addition (gaps) to the planned projects.

The five transmission portfolios explored in the study are summarized in the graphic in Figure 7.

Figure 7: Summary of Study's Transmission Portfolios



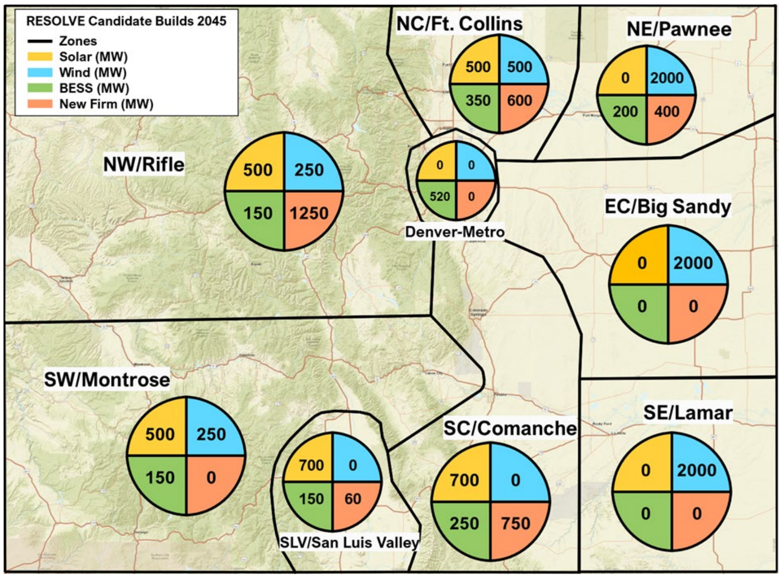
Reference Case Portfolio

As detailed in the methodology section of this report, the 20-year Colorado resources needed to maintain reliability, meet energy demands, and achieve policy goals, were identified by RESOLVE and were subsequently allocated to substations in nine resource zones using the busbar mapping methodology. The almost 15 GW of incremental resources were added, including:

- 7 GW of Wind
- 3 GW of Solar PV
- 3 GW of New Firm
- 1.8 GW of 4-hour Battery Storage

The allocations for wind and solar were based on resource quality and available hosting capacity, the cost of upgrades to increase capacity, and commercial interest by developers, as well as feedback from stakeholders. The new firm generation capacity – a generic resource type – was generally cited at retiring coal facilities like Craig, Comanche, and other locations that have reasonable access to transmission and gas infrastructure. New battery storage was co-located with existing and new solar along with some placed in the Denver metro area. The figure below shows the zonal allocations of resource additions in the Reference Case.

Figure 8: Map of Zonal Allocations in 2045 Reference Case



A summary of the busbar mapping for these resources is provided in the table below.

Table 3: Generation Capacity (MW) Busbar Mapping for Reference Case

Zone	Substation	Wind	Solar	Firm	BESS
Eastern	Goose Creek	1,200			
	Landsman Creek	400			
	Lincoln	400			
NC	Husky	100	500		150
	Keota	400			
	Rawhide			500	
	Ft. St. Vrain				200
	Ft. Lupton			100	
NE	Canal Crossing	800			
	North Yuma	400			
	Spring Canyon	400			
	Wray	400			
	Pawnee			400	200
NW	Craig		500	600	150
	Hayden			300	
	McBryde			350	
	Meeker	250			
SLV	San Luis Valley		700		150
	Alamosa			60	
SC	Sandstone		700		250

Zone	Substation	Wind	Solar	Firm	BESS
	Comanche			500	
	RD Nixon			250	
SE	**May Valley**	2,000			
SW	**Lost Canyon**	250			
	Montrose		500		150
Metro	**Cherokee**				220
	Daniels Park				200
	Waterton				100
TOTAL		**7,000**	**2,900**	**3,060**	**1,770**

As discussed in the *Summary of Study Methodology* section, the powerflow assessment evaluated system performance from both reliability and deliverability perspectives. The portfolio of projects for the 20-year Reference Case required to meet the reliability, deliverability, and economic needs of the Colorado high-voltage system consists of approximately $4.5 billion in capital investment and 3,700 miles of transmission upgrades. Those figures are broken into the categories of upgrades as shown in the following table.

Table 4: Reference Case Portfolio Summary

Upgrade	Miles	Cost ($M)
Greenfield / New	548	$1,957
Rebuild to Double-Circuit	269	$1,281
Reconductor & Transformer Upgrades/Additions	2,883	$1,265
TOTAL	**3,700**	**$4,503**

Figure 9: 20-Year Reference Case Transmission Portfolio

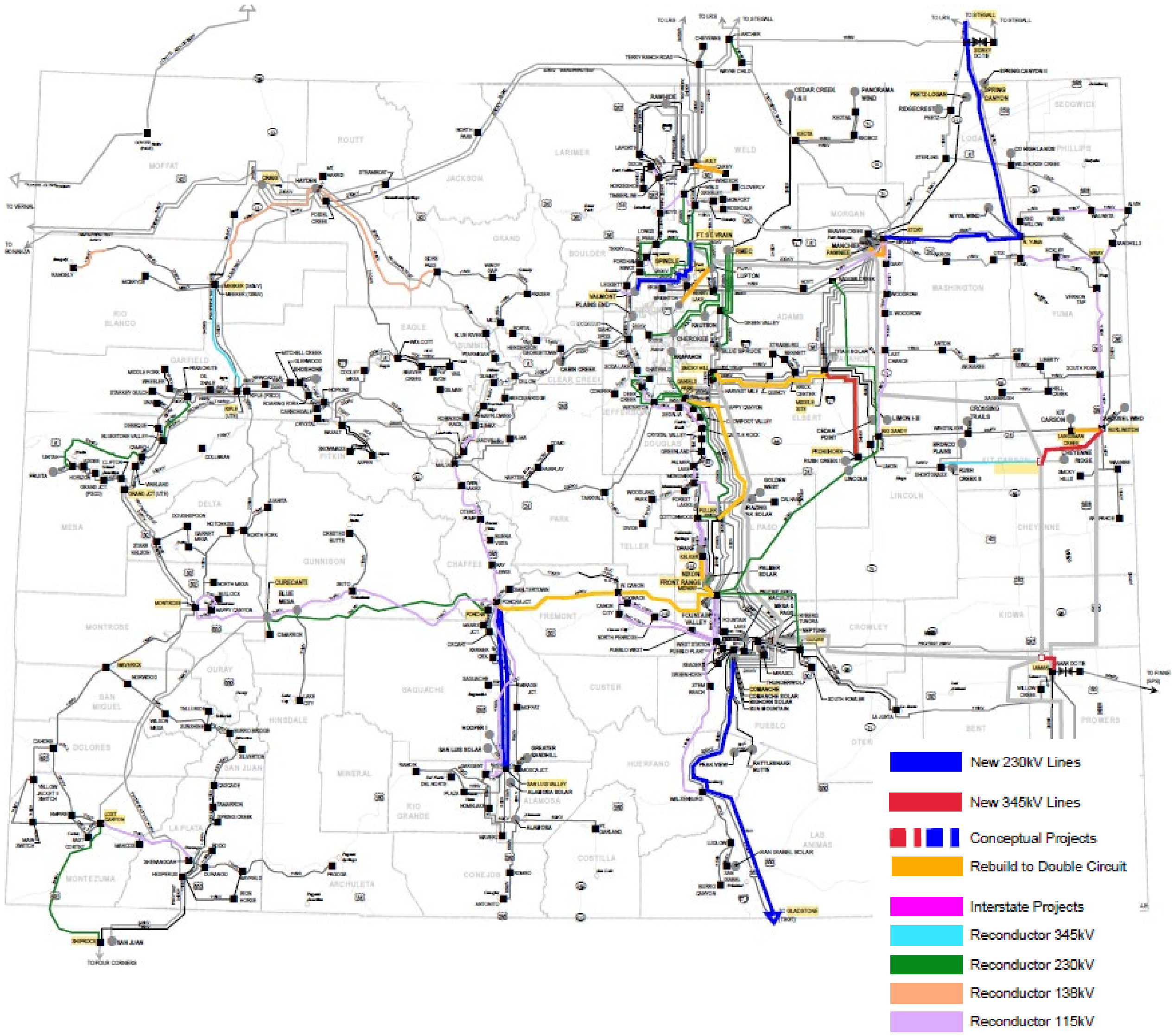


Table 5: 20-Year Reference Case Portfolio - New Greenfield Transmission

Project	Miles	Cost ($M)
New Lamar – May Valley 345kV Line	5	$38
New Missile Site – Pronghorn 345 kV	45	$151
New Comanche/Huckleberry-Gladstone 230kV Line	163	$620
New San Luis Valley – Poncha 230kV Line double-circuit	64	$307
New Burlington - Goose Creek 345kV Line	36	$169
New N. Yuma - Spring Canyon – Sidney – Stegal 230kV line	189	$565
New N. Yuma - Story 230kV Line	46	$107
SUB-TOTAL	**548**	**$1,957**

Table 6: 20-Year Reference Case Portfolio - Rebuilt Existing Transmission

Project	Miles	Cost ($M)
Rebuild Kelker–RD Nixon/Front Range–Midway 230kV to double ckt	20	$49
Rebuild Burlington – Landsman Creek 230kV line to double circuit	5	$23
Rebuild Husky - Ault 230kV line to double circuit	6	$21
Rebuild Ft. Lupton – JL Green 230kV line to double circuit	20	$66
Rebuild Story to Pawnee 230kV line to double circuit	11	$29
Rebuild Ft. St. Vrain - Spindle - Valmont Line to double circuit	38	$119
Rebuild Poncha – Midway 345kV Line to double circuit	80	$505
Rebuild Daniels Park – Fuller 230kV Line to double circuit	46	$207
Rebuild Smoky Hill – Missile Site 345kV Line to double circuit	43	$261
SUB-TOTAL	**269**	**$1,281**

Table 7: 20-Year Reference Case Portfolio- Reconductoring

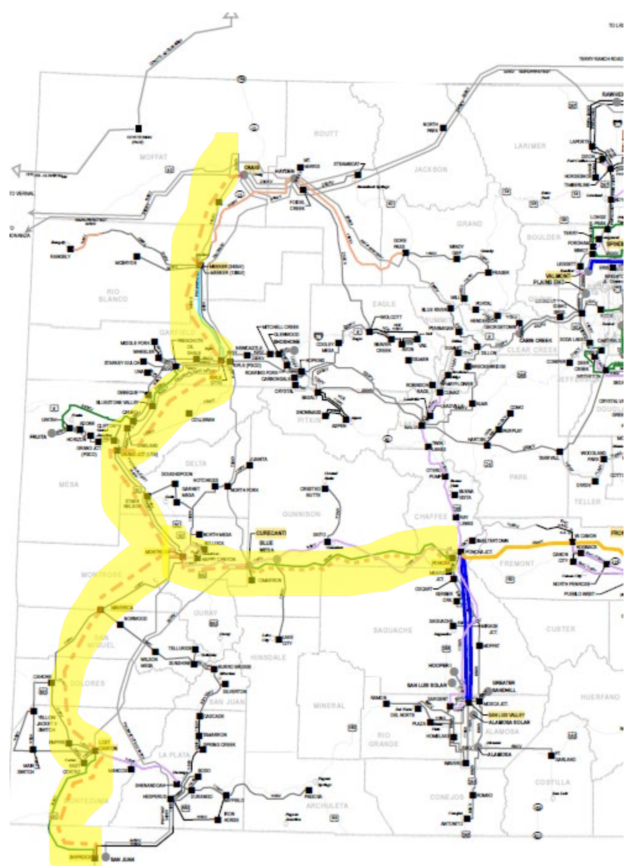
Project	Miles	Cost ($M)
345kV Transmission Lines	94	$56
230kV Transmission Lines	1,079	$395
138kV Transmission Lines	111	$41
115kV Transmission Lines	1,146	$425
Transformer Additions	N/A	$163
Metro Reconductors and TX	453	$185
SUB-TOTAL	**2,883**	**$1,265**

Conceptual Alternatives

In addition to the Reference Case Portfolio, additional conceptual alternative upgrades could be needed based on different resource locations or inter-state policy or market outcomes. **These projects are considered alternatives to proposed Reference Case Portfolio projects.** These alternatives consist of individual projects that could be considered on a case-by-case basis, depending on the driving factors listed above. The estimated cost for the entire list of Conceptual Alternatives is about $4.8 billion and includes over 1,100 line-miles of transmission, noting that the study did not plan for or identify a scenario where the entire list of Conceptual Alternatives would be required.

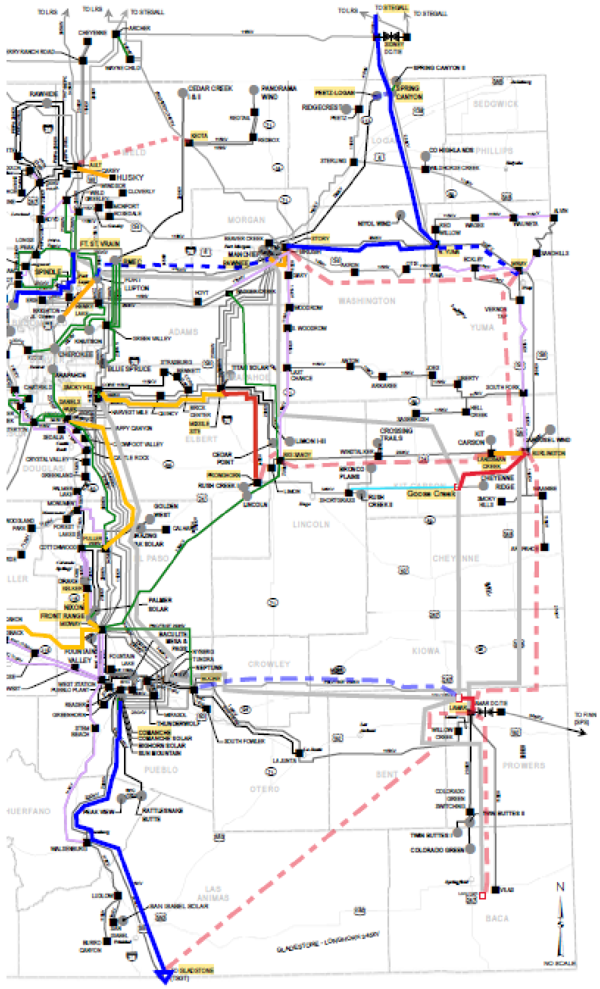
One of the most significant projects in the Conceptual Alternatives list consists of adding 345-kV transmission to Colorado's Western Slope transmission network. The study found that higher resource development on the Western Slope, especially in the northwest around the Craig/Hayden area, could drive the need for new 345-kV transmission between the Craig and Four Corners areas. That transmission could be complemented by new 345-kV transmission between Montrose and Poncha to help provide power delivery from the Western Slope to the Front Range. The Reference Case Portfolio included new transmission from Poncha to Midway, which would allow resource delivery from the San Luis Valley. New transmission between Montrose and Poncha would bridge the transmission gap to allow resource delivery from the Western Slope to the Front Range.

Figure 10: Western Slope Conceptual Projects



Other conceptual projects include additional 345-kV transmission along the eastern edge of Colorado and from eastern Colorado to the Front Range. For example, if resources above Reference Case levels were to be located in eastern Colorado, a 345-kV transmission line from Wray to Story, Wray to Burlington, and Burlington to Pronghorn could supplement the capacity provided by the Colorado Power Pathway (which was assumed to be constructed in the study).

Figure 11: Eastern Colorado Conceptual Projects



Projects from Lamar to the Pueblo area and from Lamar to New Mexico could be alternatives to a tie between Lamar and May Valley. These alternative projects could also be driven by additional resources located in the southeast area. However, due to their higher cost, other drivers might be needed to justify their construction, such as desire to establish a stronger tie to New Mexico for added import or export capability.

Interstate Concepts

Although the focus of the overall assessment was to evaluate potential transmission needs within the state of Colorado as the study team quickly identified that those 20-year needs were significant and needed to be addressed, consideration was given to understanding how the proposed portfolio might benefit, support or encourage interstate transmission that could interconnect the Colorado system to adjacent states. Stakeholders also expressed a great deal of interest in understanding how the portfolio might accommodate interstate transmission.

The Interstate Concept analysis identified transmission solutions that increase in the ability to move power into and out of Colorado. Three interstate concepts were considered as part of the exploration: interconnections between Colorado and Utah (Northwest Concept), Colorado and New Mexico (Southwest Concept), and Colorado and Wyoming (Northern Concept).

Table 8: Interstate Concepts

Concept	Project	Miles	Cost ($M)
Northwest (Colorado – Utah)	Craig to Coyote 345kV line	38	$178
Southeast (Colorado – New Mexico)	New Longhorn to Gladstone 345kV Line	140	$538
Northern (Colorado – Wyoming)	Reconductor Ault to Archer 230kV line	44	$23
	Reconductor Ault to Terry Ranch 230kV line	32	$14

The operational performance of each of the concepts was studied by using the 20-year production cost model, evaluating how the projects changed system congestion.

Northwest Concept

Northwest Colorado is electrically tied to the Utah system by a single 345-kV line and two 138-kV lines. The combined transmission lines define the WECC Path 30, or "TOT 1A". The path has an east-to-west transfer limit of 650 MW. The Northwest Concept consists of connecting the existing 345-kV system in northwest Colorado to the PacifiCorp Gateway South transmission line, which will run between Wyoming and Utah. The specific Gateway South project is referred to as Segment F and consists of a new 416-mile, 500-kV transmission line between the Aeolus Substation, near Medicine Bow, Wyoming, to the Clover Substation, near Mona, Utah. Segment F of Gateway South cuts through northwest Colorado, providing an opportunity for a relatively short interconnection between the two systems.[11]

The interconnection was modeled as a 38-mile 345-kV transmission line from Craig Station to the planned Coyote Substation, which is a point on the Aeolus – Clover line that is intended for the installation of series compensation. The estimated cost of such a project is about $180 million. The map below shows the concepts.

[11] Gateway South is part of the larger PacifiCorp Energy Gateway Project, which is intended in part to deliver renewable energy from Wyoming to customers in the west, including Idaho, Washington, and Utah.

Figure 12: Northwest Concept

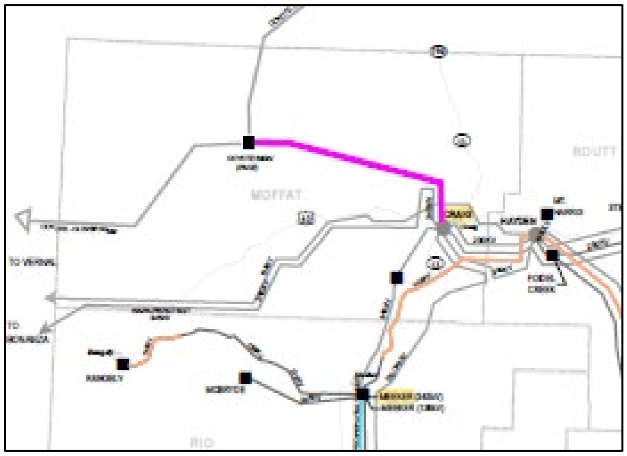


Figure 13: Gateway Transmission Complex

This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

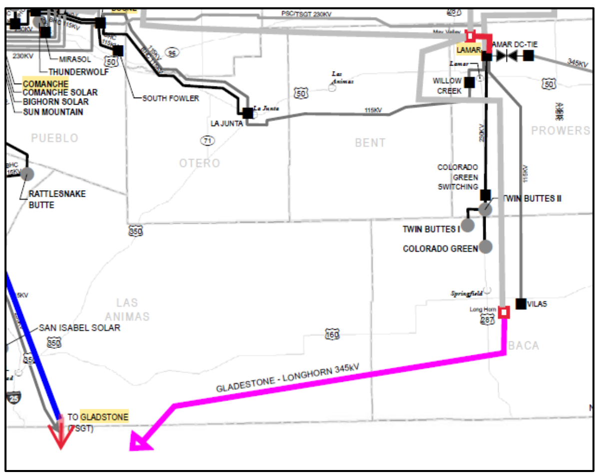
The congestion assessment for the Reference Case exhibited material congestion on the existing transmission path between Colorado and Utah. This path is known as WECC Path 30, or TOT 1A. Adding the Craig – Coyote 345-kV concept reduced congestion hours from 780 to 2, and annual congestion costs from about $40 million to less than $200,000.

Southeast Concept

The existing transmission between Colorado and New Mexico is very limited. Other than the 345-kV and 230-kV ties into the Four Corners area in the southwest part of the state, there is only a single 230-kV line between the Pueblo, Colorado area and Gladstone, New Mexico. The Southeast Concept consisted of connecting planned and conceptual 345-kV transmission in southeast Colorado to existing transmission in northeast New Mexico. A 345-kV line was modeled from the conceptual Longhorn 345-kV substation to the existing Gladstone 230-kV substation, and 345/230 kV transformation at Gladstone. Longhorn is a component of the Xcel Energy (Public Service Company of Colorado), Colorado's Power Pathway (CPP) project. Specifically, May Valley to Longhorn is considered by Public Service Company of Colorado (PSCo) to be a conceptual extension to the planned CPP that consists of a 90-mile 345-kV line from May Valley, near Lamar, Colorado, to a new Longhorn Substation, near Vilas, Colorado in Baca County.

The Southeast Concept was modeled as a 140-mile 345-kV transmission line from Longhorn Substation to the existing Gladstone 230-kV substation, along with new 345/230-kV transformation at Gladstone. The estimated cost of the project is about $540 million.

Figure 14: Southeast Interstate Concept



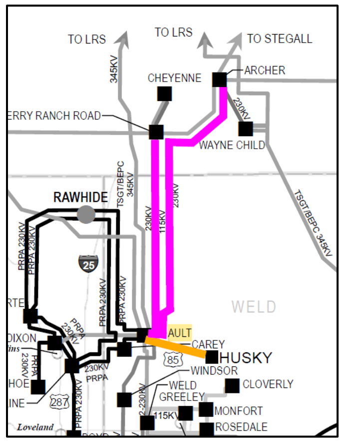
The congestion assessment of the Reference Case exhibited congestion on the existing Comanche – Huckleberry (Gladstone) 230-kV line, which is part of the 230-kV transmission that runs from Pueblo, Colorado to Gladstone, New Mexico. Adding a new Longhorn to Gladstone 345-kV line reduced congestion hours from 586 to 36, and annual congestion costs from about $6.5 million to about $250,000. Another observation is that the northern New Mexico transmission system is relatively limited in its ability to transfer power into load centers and to the west. As a result, any interstate project into New Mexico will not likely provide significant capacity benefits until transmission improvements are made in the northern part of New Mexico.

Northern Concept

The Northern Concept consisted of connecting existing transmission in northern Colorado to existing transmission in southern Wyoming. There is an existing WECC transmission path between Colorado and Wyoming known as Path 36, or "TOT 3", which presently consists of seven transmission lines. The north-to-south transfer limit is about 1,800 MW, and there is no defined limit south-to-north.

The Northern Concept interconnection was modeled by uprating two of the seven TOT 3 transmission lines: the Archer – Ault 230-kV line, and the Ault – Terry Ranch 230-kV line by reconductoring them to new conductors with higher ratings. The estimated cost of the uprates is about $37 million.

Figure 15: Northern Concept



The congestion assessment of the Reference Case exhibited some congestion on the existing transmission path between Colorado and Wyoming. This path is known as WECC Path 36, or TOT 3. By reconductoring the Ault to Archer and Ault to Terry Ranch 230-kV lines, TOT 3 congested hours were reduced from 82 to 4, and annual congestion costs were reduced from about $2.1 million to less than $20,000. Based on this, the Ault to Archer and Ault to Terry Ranch interstate expansion did not have a notable impact on congestion. This is largely because the Reference Case portfolio already mitigated most of the congestion on TOT 3. Prior to the Reference Case Portfolio, TOT 3 was congested for nearly 10% of the year with an annual congestion cost of $31 million. After the Reference Case Portfolio was implemented, those values dropped to <1% and $2.1 million, respectively. Based on this, the upgrades in the Reference Case Portfolio are more critical for addressing WY-CO congestion than the upgrades in this Northern Concept.

High Demand Scenario Portfolio

The purpose of analyzing the High Demand Scenario was to understand how transmission needs change under a future with very high demand in Colorado. The scenario assumes that Colorado would experience load growth consistent with NREL EFS High/Moderate Electrification. This future forecasts Colorado's Peak Load at around 20 GW by 2045. This growth captures increasing demand due to electrification, data center growth, and other new point loads like hydrogen production.[12]

Capacity expansion modeling indicated that for such a future, the Colorado loads could be 45% higher than for the Reference Case. The resource need associated with that projection was determined to be

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[12] https://www.nrel.gov/analysis/electrification-futures.html

approximately 7 GW of additional resources. That increase was modeled by adding approximately 5,200 MW of firm generation, 1,100 MW of solar, and 1,200 MW of energy storage as shown below.

Table 9: Resource & Load Levels in High Demand Scenario

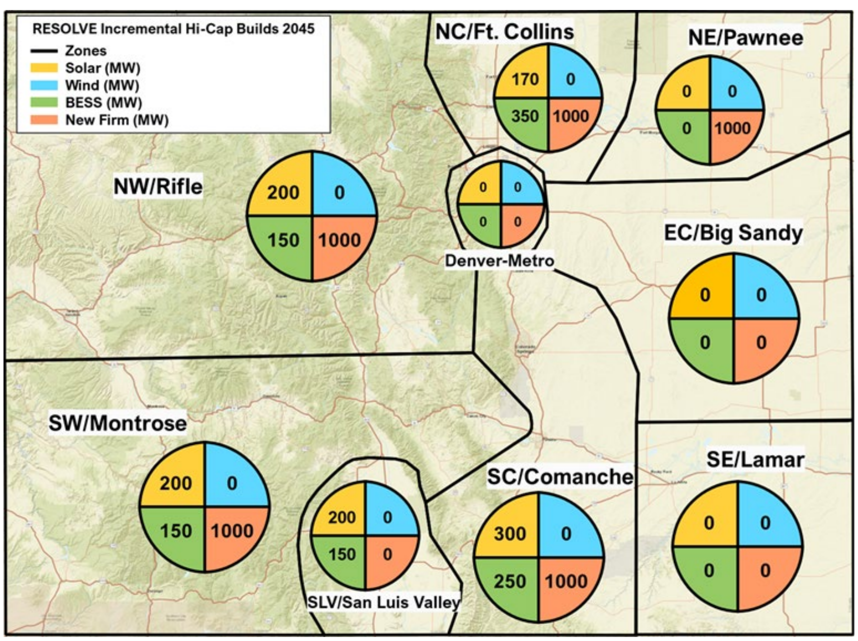
Resource Type	Reference	High Demand	Difference
Firm (gas or clean firm)	3,060	8,193	5,134
Wind	6,929	6,937	8
Solar	2,875	3,941	1,066
Battery	1,769	2,949	1,180
Resource Total	**14,632**	**22,019**	**7,387**
Peak Load	**13,850**	**20,023**	**6,173**

The additional resources were mapped to the nine zones as shown below.

Table 10: Resource mapping for the High Demand Scenario

Zone	Wind	Solar	Gas (or clean firm)	BESS	BESS-Model	Total
Eastern	0	0	0	0	0	0
NC	0	170	1,000	350	150	1,320
NE	0	0	1,000	0	50	1,050
NW	0	200	1,000	150	100	1,300
SLV	0	200	0	150	50	250
SC	0	300	1,000	250	150	1,450
SE	0	0	0	0	0	0
SW	0	200	1,000	150	100	1,300
TOTAL	**0**	**1,070**	**5,000**	**1,050**	**600**	**6,670**

Figure 16: Incremental Zonal Allocations for High Demand



In general, the additional firm and battery storage resources were located at locations that already had those resources in the Reference Case. Additional solar resources were located based on the busbar mapping methodology.

Creating models for a 20-year scenario with an additional 50% of load growth was technically challenging and models struggled to maintain stability. Important transmission expansion aspects of the High Demand Scenario included the need for the conceptual 345-kV transmission on the Western Slope, including a new Craig - Montrose – Shiprock 345-kV line and a new Montrose – Curecanti – Poncha 345-kV line. Additional transmission upgrades included almost 200 miles of new 115-kV lines, almost 100 miles of existing 230-kV lines rebuilt to double-circuit, and over 1,200 miles of 115-kV, 138-kV, and 230-kV transmission reconductoring.

The total incremental cost of the High Demand Scenario Portfolio was over $4.2 billion, which is essentially double the cost of the Reference Case Portfolio (which is also required for this scenario). A map of the portfolio projects is shown below.

Figure 17 High Demand Portfolio

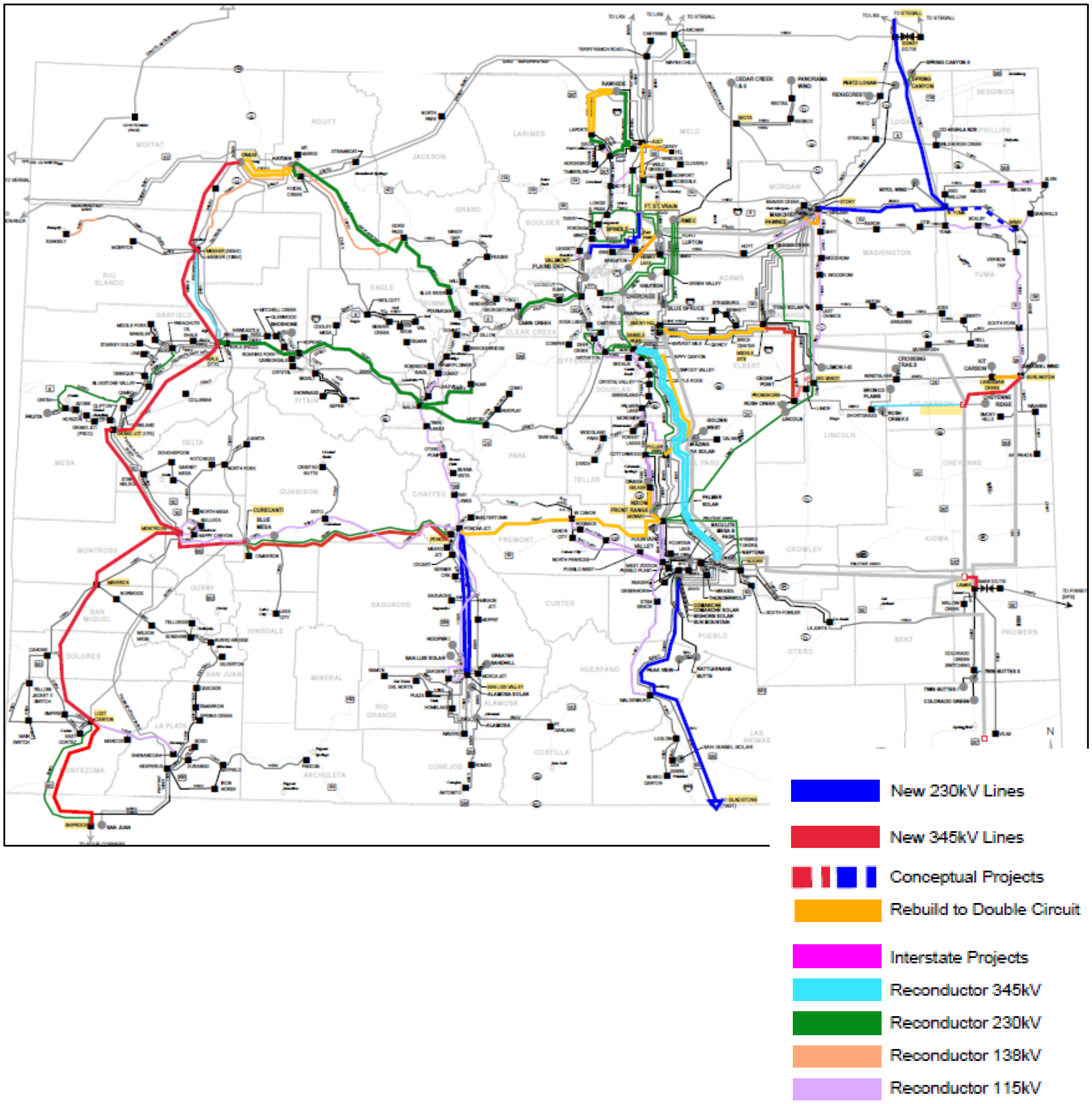


Table 11: High Demand Portfolio Projects

Project	Miles	Cost ($M)
Reconductor 115, 138, 230 kV	1,142	$421
New Transformers	N/A	$59
New 115kV lines	182	$340
Rebuild 115kV & 230 kV lines to double circuit	245	$647
New Montrose-Maverick-Lost Canyon-Shiprock 345kV Line #1	170	$840
New Montrose-Grand Jct-Rifle-Meeker-Craig 345kV Line #2	199	$1,124
New Montrose-Curecanti-Poncha 345kV Line #1	103	$367
Reconductor Daniels Park-Tundra 345kV #1 & #2	94	$70
Rebuild Greenwood – Prairie – Daniel Park 230kV to double circuit	8	$33
Rebuild Glenn – Washington 230kV to double circuit	4	$16
Rebuild Ault – Weld 230kV to double circuit	12	$45
Rebuild Laporte – Rawhide 230kV to double circuit	21	$77
Rebuild Craig – Hayden East and Craig – Hayden West to double circuit	54	$199
TOTAL		**$4,239**

SPP Wind Integration Portfolio

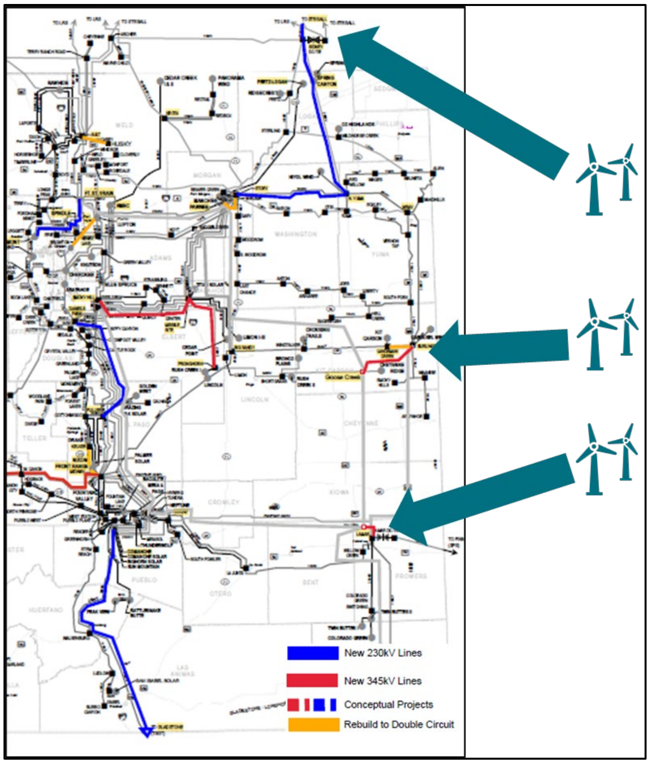
The objective of the SPP Wind Integration Portfolio was to understand how regional integration between SPP and WECC, and specifically, between SPP and the eastern edge of Colorado might impact the 20-year portfolio. The integration was simulated by assuming wind generation could be injected at the back-to-back HVDC ties that connect the WECC and SPP systems. Three concept locations were evaluated: the existing Lamar HVDC tie, the existing Sidney HVDC tie, and a conceptual DC tie at Burlington. The scenario contemplated a 2 GW injection into Colorado from SPP. Notably, the study did not assume an assessment of expanding HVDC Tie capability to enable this transfer, nor did it assess any upstream transmission expansion needs on the SPP system (given the study was focused on the Colorado grid). However, prior work has been completed by the Colorado Coordinated Planning Group (CCPG) exploring DC tie expansion.[13]

Three injection concepts were modeled and evaluated:

- 2 GW injected at Lamar
- 1 GW injected at Lamar and 1 GW injected at Burlington
- 1 GW injected at Lamar and 1 GW injected at Sidney

[13] A study performed by the CCPG explored the cost and feasibility of expanding DC tie capacity and is available for review here: https://doc.westconnect.com/Documents.aspx?NID=21116

Figure 18: SPP Integration Alternatives



To provide meaningful results, some thought was given to how the SPP resources should be dispatched in concert with the Colorado generation. If it was assumed that the SPP resources would completely displace eastern Colorado generation, then there would likely be no impact to the proposed transmission portfolio. Therefore, generation in eastern Colorado was modeled at relatively high levels in addition to the SPP injection. The increased generation output was scheduled to western Colorado and outside the state to capture the impacts to the transmission system.

Each of the concepts required transmission upgrades west of Lamar, including:

- Increasing the capacity between Lamar and May Valley by adding a second 345-kV line
- Increasing the capacity of the existing 230-kV line between Lamar – Boone – Midway
- Additional 345/230-kV transformation at Lamar.

The concept that injected all of the 2 GW at Lamar was the lowest-cost alternative. Table 11 summarizes the upgraded transmission miles and estimated costs for the alternatives.

Table 12: SPP Integration Summary

Alternative	Upgrade Miles	Cost ($M)
Lamar 2 GW	151	$161
Lamar 1 GW, Burlington 1 GW	5,417	$396
Lamar 1 GW, Sidney 1 GW	306	$173

Note that costs associated with injecting the SPP wind at the DC ties were not estimated, as stated above. These costs would be significant since they would entail either additional back-to-back DC ties or lengthy, radial lines from SPP into existing Colorado substations. The study did not consider alternative locations to expand connectivity to SPP, although stakeholders involved in the process did agree to focus the assessment on Colorado upgrades due to DC tie expansion.

Table 13: Detailed SPP Integration Results

Concept	Project	Miles	Cost ($M)
All	Lamar-May Valley 345kV #2	5	$38
	Reconductor Lamar-Boone-Midway 230kV #1	146	$44
	Lamar 345/230kV XFMR #2 & #3		$28
	Sub-total All Concepts		**$109**
Lamar 2GW	Increase rating of Lamar-May Valley 1&2 + Lamar 345/230kV Tx		$52
	Total Lamar 2 GW		**$161**
Lamar 1 GW Burl 1 GW	Burlington-Wray 345kV #1	71	$117
	Wray-N Yuma 230kV #2	32	$67
	Reconductor 230kV: Burlington-Wray, Windtalker-Big Sandy, N.Yuma-Story	168	$61
	New 345/230kV Transformers (3)		$42
	Total Lamar 1 GW, Burlington 1 GW		**$396**
Lamar 1 GW Sidney 1 GW	Reconductor 230 kV: Story-N.Yuma, N.Yuma- Spng Cany, Badger Crk-Henry Lake 230	155	$61
	Upgrade 230/115kV XFMRs (Sidney, N Yuma)		$2
	Total Lamar 1 GW, Sidney 1 GW		**$173**

3. Study Observations and Transmission Gaps

The CETA Transmission Capacity Expansion Study offers critical insights into the transmission infrastructure needed to meet Colorado's long-term energy demand and policy goals. As Colorado continues its transition to clean energy, the state will experience critical transmission needs across the 10- to 20-year planning horizon. This study highlights transmission planning gaps and the necessary investments required to ensure reliability and efficiency over the next two decades.

The key takeaways from the study are summarized below:

1. **Transmission needs over the next decade are limited to specific regions within Colorado but must be addressed to achieve state policy objectives.** The 10-year needs identified in the study are based on resource and load deployments that are consistent with Colorado utility ERPs. In the 10-year assessment, transmission gaps were identified in San Luis Valley, Northeast Colorado, and Southeast/South Central Colorado. These regions of the state face severe grid constraints, driven by forecasted generation energy deployment and increasing electricity demand. **The study concludes that the state may not be planning sufficient transmission capacity to accommodate the growing load and resource adoption levels found in utility ERPs.** Since ERPs reflect resource plans that meet state emission reduction goals, this study's results indicate that additional transmission infrastructure – such as what is envisioned in the 10-year Reference Case – will be necessary to meet the state's clean energy goals.

   Issues identified in the 10-year horizon assessment are exacerbated in the 20-year planning horizon. As a result, these areas are suitable for "right-sizing" transmission investments, where scaling up the size of planned infrastructure in the near term can more effectively meet future demand. One potential use for this CETA Transmission Expansion Study is to inform efforts to right-size near-term upgrades planned in the state, offering a holistic and long-term view of what is needed for the various corridors.

2. **All 20-year horizon scenarios point to significant future transmission need.** The three scenarios analyzed—Reference Case, High Demand, and Regional Integration—all indicate significant transmission investment is required over the next 20 years. The 20-year Reference Case Portfolio alone calls for $4.5 billion in grid investment, including nearly 550 miles of new greenfield lines and over 3,000 miles of reconductoring and rebuild projects. This scale of transmission buildout is essential to meet growing electricity demand and integrate renewable energy and capacity resources. 44% of this projected investment pertains to transmission projects not yet proposed by utility planners or developers, indicating the need for ongoing strategic transmission and resource planning in the state.

3. **20-Year needs are driven heavily by load growth and resource deployment.** The study forecasts a peak load increase from 10 GW today to approximately 14 GW by 2045, and as much

as 20 GW under the High Demand scenario. In addition, 2035 and 2045 the study projects that Colorado will add 10 GW of renewable energy, 2 GW of storage, and 3 GW of firm resources with substantial capacity located in remote regions like the Eastern Plains and the San Luis Valley. These additions, on top of the 8 GW planned to be added between now and 2035 under current Electric Resource Plans (ERPs) will place considerable pressure on the state's transmission infrastructure.

4. **Existing infrastructure can be leveraged to address many needs.** A significant portion of the transmission needs identified can be addressed by upgrades to existing infrastructure. Reconductoring projects, which involve upgrading existing lines to higher capacity, account for nearly 80% of the line miles identified in the study but represent only 28% of the total portfolio cost. These projects are a cost-effective means to provide more capacity in existing transmission corridors and help to minimize land impacts while still prioritizing grid expansion. The study results demonstrate the strategic importance of existing transmission corridors in the state. Rebuilds of existing lines to double-circuit account for a smaller amount of line miles (7%), but another 28% of the portfolio costs. These projects leverage the ability to utilize existing corridors but may require additional rights of way. CETA is uniquely positioned to help Colorado ensure that existing corridors are efficiently and strategically leveraged, while new corridors are pursued when technically supported by the long-term needs of the system.

5. **New greenfield transmission development is required in all scenarios.** Despite the potential for infrastructure upgrades, all three scenarios revealed the need for substantial greenfield transmission projects. The Reference Case Portfolio identifies 550 miles of new greenfield lines at a cost of $1.96 billion, with key projects like a new San Luis Valley – Poncha 230-kV line, a new Goose Creek – Burlington 345 kV line, and a new Lamar – May Valley 345-kV line. These projects are critical for transferring power from where it is generated to where it is consumed.

6. **Opportunities exist to improve transmission efficiency through coordination.** The study identified several opportunities to improve the efficiency of transmission projects through enhanced coordination, particularly with large upgrades such as the Colorado Power Pathway (CPP). For example, Goose Creek – Burlington line and May Valley – Lamar lines represent additional ties between the planned CPP and existing transmission that provide material benefits at relatively low cost. In addition, reconductored projects should be evaluated further to determine whether rebuilding or adding new transmission lines would provide more cost-effective solutions. For example, expanding transmission capacity to the San Luis Valley, with joint efforts from Colorado utilities, could improve both reliability and resource deliverability.

7. **Higher than forecasted loads will trigger the need for more transmission capacity.** The High Demand Scenario showed that increasing load by 5 GW due to electrification, data center deployment, and other new loads, would nearly double the required transmission investment by

2045. The scenario calls for an *additional* $4.2 billion in upgrades beyond the Reference Case, with significant new 345-kV transmission on the Western Slope, and nearly 1,200 miles of incremental reconductoring at lower voltage levels. This finding highlights the importance of incorporating load growth sensitivities into transmission planning. This finding suggests that transmission could become the bottleneck for certain types of economic development in Colorado.

8. **Future grid expansion can be leveraged to support increased transmission connectivity between Colorado and SPP**. The SPP Integration Scenario analysis indicated that expanding transmission links between Colorado and the Southwest Power Pool (SPP) represents one option to assist the state in meeting its clean energy targets. Injecting 2 GW of wind power at the Lamar DC tie would require 151 miles of new transmission at a cost of $161 million (in addition to the Reference Case Portfolio, but not considering costs of HVDC converter station expansion). Based on the scope of this study, which focused on capacity availability on the Colorado side of the DC ties, results indicate that the Reference Case Portfolio would need to be expanded modestly to increase connectivity to SPP (assuming converter stations are upgraded to enable higher transfers, as well as any upstream upgrades in the SPP territory).

   As far as market choices are concerned, such as RTO formation, the Colorado transmission system shows limited sensitivity to broader market expansion choices as observed physical congestion in and around the state remains largely unchanged across different market constructs.[14] For this reason, the study did not focus narratives on this portion of the Market Integration scenario.

9. **The Conceptual Alternatives represent 1,100 miles of projects that may be either substitutes or additions to the Reference Portfolio identified in the study, recognizing that different resource, policy, or market outcomes may necessitate materially different transmission solutions.** These alternatives reflect Colorado's need for flexibility as the state's energy landscape evolves.

10. **Upgrades to the intrastate system support future interstate expansion.** Strengthening Colorado's intra-state transmission infrastructure is critical to unlocking interstate transmission opportunities. The study found that addressing internal transmission bottlenecks will facilitate more effective connections with neighboring regions such as Wyoming, Utah, New Mexico, and the Southwest Power Pool (SPP). While many opportunities exist to enhance Colorado's interstate transmission capacity, these projects will only reach their full potential if the state's internal

[14] As agreed to by stakeholders, the study's Reference Case assumed that all Colorado utilities joined the SPP West RTO. A sensitivity was performed to evaluate how interstate congestion changed when the market footprint was changed to a West-wide day-ahead market. The results did not indicate any major changes in interstate congestion and as a result, no new transmission was proposed or explored as a result of the scenario. In both cases, flow-based transmission constraints were used to limit transmission flows (versus contract path constraints).

constraints are resolved. Internal congestion could limit the benefits of these interstate projects, as it would hinder the efficient transfer of energy across state lines. Prioritizing in-state transmission upgrades alongside interstate development will ensure that Colorado's grid is well-positioned to meet future demand growth. This dual focus will enable Colorado to strengthen market access, improve grid resiliency, and continue progressing toward its clean energy and reliability goals.

Transmission Gap Analysis

Colorado faces significant long-range transmission development gaps that CETA is positioned to help address. Addressing these transmission gaps as they evolve over the approaching 10- to 20-years will be critical to meeting policy goals and reliability needs of Colorado. Transmission gaps in this study were identified by comparing the Reference Case Portfolio and Scenario Portfolios described above with conceptual upgrades not already included in the modeling exercise. We also surveyed stakeholders via the comment process for the Initial Report, asking them if any developers or utilities were pursuing the projects identified in the study.

The goal of the gap analysis is to inform CETA's decision-making process, helping CETA and planners in the state prioritize and support projects that align with Colorado's long-term transmission goals. By identifying these gaps, CETA can better focus on addressing the most pressing transmission needs and enable potential project partnerships. The gap analysis provides a roadmap for CETA to collaborate with utilities, developers, and other stakeholders to fill gaps that remain unaddressed, ensuring that Colorado's transmission system can support growing energy demands and facilitate the state's clean energy transition.

Key transmission gaps identified in the study are highlighted below.

- **Near-term transmission gaps.** The ten-year assessment confirmed known transmission issues in certain areas of the state, including the San Luis Valley, eastern Colorado, and the Denver metro. The 20-year assessments exacerbated the issues. It is understood that utilities have been actively evaluating most if not all of those issues and developing plans that could resolve those needs. However, since no firm plans are in place, we have identified the areas listed above as a potential gap that likely needs to be addressed.

  The San Luis Valley is one area of Colorado that has been studied extensively and numerous alternatives have been evaluated to not only increase reliability but provide resource injection capability. There have been some minor upgrades to existing transmission, but there are no firm plans to implement any transmission projects in the area that would enable significant resource accommodation.

PSCO has recently completed transmission studies meant to accommodate its most recent ERP.[15] The objectives stated in the report were to identify impacts to the network based on the ERP generation, identify transmission improvements, and ensure "projects are right sized for the to minimize the need for further incremental upgrades to the facilities identified in this Study Report where possible". Since the study horizon only reached out to 2028, only three projects internal to the Denver-metro system were identified. The study noted that the recommendations only address the most recent ERP portfolio, and that additional studies will be needed to evaluate future needs beyond the horizon of that study. The future studies referenced will be critical to identify and recommend projects needed to meet likely performance gaps in the 10-year horizon.

- **Long-term transmission gaps.** In performing the gap analysis for the 20-year planning horizon, the greenfield and rebuild projects are considered the most important elements of the portfolios, since the reconductor projects are more easily implemented (no new rights-of-way in many cases), and are often identified through the course of normal system planning. Such projects would likely be uncovered by utilities during typical planning study efforts.

  However, even though the reconductor (and transformer) projects were about 28% of the total Reference Case Portfolio cost, the reconductor projects accounted for almost 80% of the overall line miles. The significant amount of reconductors needed in this assessment can provide utilities and transmission owners with a foundation for further evaluation. Based on their knowledge of the system, there could be potential for greenfield and rebuild projects that might provide wider ranging benefits and efficiencies compared to a group of reconductored facilities. Also, with the methodology used, the reconductoring implied that the capacity of existing transmission is inadequate, and it was assumed that lines can be reconductored utilizing the same rights of way and existing transmission towers. However, some lines may be in such a condition that they need to be rebuilt in order to make any changes, due to the age and condition of the existing structures. In those instances, utilities could also consider rebuilding those lines to double-circuit and/or higher voltage capabilities which would provide more benefit than rebuilding to simply reconductor the lines. It is also important to point out that about 16% of the line miles and costs associated with the reconductor category were located within the Denver-metro area. Public Service Company of Colorado may address those issues in other planning forums.

  The study identified a 20-year transmission portfolio requiring more than $4.5 billion in investments to address Colorado's future grid needs. 44% of this capital pertains to greenfield upgrades that have not yet been proposed by utility planners or developers. This is the largest planning gap the study identified.

  Although some of the portfolio and conceptual projects identified as needed in this study may have been contemplated by utilities and stakeholders, there is only one project currently being

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15 https://www.rmao.com/public/wtpp/Operating_Studies/ERP%20Phase%20II_Transmission%20Planning%20Study_10.11.24.pdf

implemented that aligns with the portfolio, which was discovered through stakeholder input. That project is the Husky – Ault 230 kV line which is part of the PSCO Northern Colorado Area Plan. The planned project was included in the base models, but PSCO stakeholders pointed out that the line is planned to be double-circuit-capable.

- **Interstate planning gaps.** The study also explored the potential of three interstate transmission concepts to strengthen Colorado's connections with neighboring states, such as Wyoming, Utah, and New Mexico. These projects are not under development and represent gaps in the state's transmission network that could be filled to improve regional power flow and enhance market access. Based on responses to the Initial Report, **stakeholders are not currently pursuing development of any of the interstate transmission solutions identified in the study**. However, other solutions, aside from those identified in this study, may exist and could address these interstate needs.
- **Transmission gaps to accommodate high load growth.** Finally, the High Demand scenario highlighted an *additional* $4.2 billion in required investment beyond the Reference Case to meet the demands of more aggressive electrification and load growth. This scenario primarily emphasized the need for reconductoring and transmission upgrade projects. If this high-demand growth materializes, these projects or similar ones will become critical to filling a substantial gap in the transmission system. Stakeholders indicated they are not currently pursuing any of the updates identified as needed for the High Demand scenario.

CETA's Prioritization and Next Steps

Upon release of the Initial Report, stakeholders were invited to provide their input on how CETA should prioritize projects identified in the study, and what steps CETA should take in the near term in response to the needs identified. This feedback, along with additional guidance from Energy Strategies, is summarized below.

Project Prioritization

The CETA Transmission Capacity Expansion Study identified a significant long-term need for transmission, with a Reference Case Portfolio that calls for $4.5 billion in grid investment that is currently unplanned. CETA can consider the following factors when prioritizing potential development projects.

Prioritization Factor	Guidance
Catalyze transmission development	Prioritize projects with broad statewide benefits, with a focus on those unlikely to proceed without CETA's involvement. Focus on projects beneficial to ratepayers but less attractive for utility investment (i.e., certain reconductoring/rebuilding).
Maximize clean energy resources	Focus on projects that maximize clean energy integration and support Colorado's goal of net-zero emissions by 2050. Evaluate

	based on the renewable generation enabled per dollar spent (MWh/$).
Enhance connectivity	Prioritize projects that improve connectivity within Colorado and enhance interstate or interregional links for resource sharing and clean energy access, particularly those needing multi-utility collaboration.
Promote right-sizing	Emphasize right-sized projects that accommodate future load growth and prevent future upgrades. Identify key corridors in planned portfolios for resilience and future-proofing.
Improve reliability and resilience	Focus on projects with substantial reliability and resilience benefits, potentially reducing utility planning reserve margins and enhancing grid stability.
Provide economic benefits	Prioritize projects with economic benefits, such as congestion savings, capacity cost savings, and economic development. Consider urgency, resilience impact, and economic feasibility.
Respond to commercial interest	Consider interregional projects with voluntary right-of-way acquired or projects with active development that may accelerate with CETA support. Review interconnection queue data for current needs.
Respond to increasing loads	Align with the High Demand Scenario by prioritizing transmission solutions that service increased load forecasts.
Limited to geographic scopes	Focus on critical transmission access areas, such as the San Luis Valley and TOT 3 path improvements in northeastern Colorado.
Promote advanced technologies	Prioritize projects using advanced conductor technology (e.g., ACSS, ACCC, TW) to enhance reliability, resilience, and cost-efficiency.
Limit land impacts	Minimize land impacts by prioritizing reconductoring, using pre-existing linear features like roads, and limiting greenfield developments that increase land fragmentation.

CETA has many tools at its disposal to help Colorado meet its future transmission needs and the organization will play a critical role in advancing projects identified in this study and elsewhere. While this study is complete, CETA's work on acting on the results is just beginning. As CETA considers advancing projects, it should consider the following to prioritize where it spends its limited time and resources:

- The project's ability to align with both immediate and long-term transmission needs. CETA has an ability to take a long-term holistic view of state needs that others do not.

- Prioritizing support for the most impactful projects that are unique and perhaps could not be built but for CETA's participation.
- CETA should also remain flexible to support other emerging transmission projects that align with the state's energy and policy goals, leveraging its position to foster collaboration among utilities, developers, and regulators.
- CETA should consider prioritizing transmission upgrades that are not likely to be built through the course of normal utility planning. Examples could include difficult in-state greenfield projects, projects that require multi-utility coordination to implement, and projects that are strategic for the state, such as those accessing new resource zones or better connecting with new markets.
- The costs of transmission portfolios identified in this study are substantial. CETA's revenue bonding authority could be used to help lower financing costs of certain transmission projects, which could help to reduce costs to Colorado consumers.

Near-term Steps for CETA

While outside the scope of this technical study, the Interim Report served as a unique opportunity to collect guidance from stakeholders on next steps for CETA. Stakeholders offered the following suggestions.

- **Pursue Additional Funding and Legislative Support:** Engage with the Public Utilities Commission (PUC) to garner legislative support for securing additional funding, particularly to bridge funding gaps for large-scale projects. CETA's bond authority may also help finance projects that are essential for achieving statewide energy and infrastructure goals.
- **Identify and Prioritize Multi-Value Projects:** Focus on multi-value transmission projects that provide broad benefits across Colorado. Collaborate with stakeholders to develop actionable plans to address priority transmission issues, with an emphasis on high-impact regions like the San Luis Valley and the TOT 3/northeastern areas.
- **Strengthen Stakeholder Engagement:** Establish a clear framework for how CETA will engage stakeholders in future transmission development efforts. This engagement should prioritize environmental justice and equity in infrastructure siting and planning processes. Collaborate with local planners and groups like the CCPG to ensure that community and environmental perspectives are fully incorporated.
- **Enhance Coordinated Transmission Planning:** Work with Colorado policymakers, including the PUC, to align transmission planning with statewide modeling and encourage utilities to integrate these findings into their Electric Resource Plans (ERPs). CETA should also promote more strategic, interregional planning with neighboring states (e.g., New Mexico, Wyoming) and coordinate results with other transmission planning groups.
- **Leverage Pilot Projects for Innovative Technologies:** Explore pilot projects that demonstrate the benefits of advanced transmission technologies (ATTs), virtual power plants (VPPs), and

advanced steel core conductors (e.g., ACSS/TW). Such projects can help gather valuable performance data, assess societal benefits like resilience and emissions reductions, refine load modeling methods, and accelerate the implementation of innovative solutions that improve grid efficiency and reliability.

- **Focus on Key Geographic Areas:** Direct immediate efforts toward addressing transmission challenges in specific high-priority regions, particularly the San Luis Valley and TOT 3 area in northeastern Colorado, where transmission constraints are impacting grid reliability and clean energy integration.
- **Collaborate on Reconductoring Efforts:** Coordinate with incumbent utilities and the PUC to prioritize reconductoring projects as an alternative to greenfield development. CETA can help facilitate cost-effective project alternatives that align with utility and state goals, ensuring efficient use of existing infrastructure.
- **Refine Study with a Focus on Land Impacts:** Update the study with a greater emphasis on land impact analysis, clearly identifying the tradeoffs between land use, environmental considerations, and project costs. Expanding this analysis could help identify alternatives to greenfield construction and promote solutions that minimize environmental disruption.

Future Studies

While the CETA Transmission Capacity Expansion Study establishes a foundation for addressing Colorado's future transmission needs, several areas for future work have been identified. These recommendations focus on improving the study process, enhancing modeling capabilities, expanding stakeholder engagement, and addressing gaps that were outside the initial study's scope. The following outlines key recommendations for future efforts:

- **Improved Capacity Expansion Modeling.** Future work should focus on refining the capacity expansion model used in this study to capture intra-state transmission constraints more effectively. Enhancements in modeling would allow for a more detailed analysis of tradeoffs between transmission investments and resource location/choice, enabling a more optimized grid development process (e.g., more detailed analysis of in- vs. out-of-state resource tradeoffs). This would also help to address an area of stakeholder interest: DERs and their ability to avoid transmission. This analysis could require co-optimizing state-wide resources, Distributed Energy Resources (DERs), and transmission investments. While these analyses were not feasible within the scope and timeline of this study, future iterations should prioritize the ability to co-optimize these factors.
- **Increase Engagement with Local Planners and CCPG.** While this study had robust stakeholder engagement, future efforts would benefit from more direct interaction with local planners, particularly through utility outreach and closer collaboration with the Colorado Coordinated Planning Group (CCPG). Although the CCPG has a "Conceptual Work Group" for considering long-term transmission plans beyond the typical 10-year horizon, it has been inactive for the past

decade. Reactivating this group could provide an ideal venue for follow-up studies, in-depth stakeholder engagement, and future transmission planning beyond the near-term horizon. One area of further research and coordination utilities and CETA should consider is collaborating on how existing rights of way can be best leveraged to benefit the state as this study had to make many assumptions about what was possible with certain rights of way.

- **Increase Study Timeline and Expand Study Scope.** The timeline and budget constraints of this study limited the ability to address certain complex issues and data requests from stakeholders. For example, the study was not designed to generate specific data points, such as avoided transmission costs or a transmission supply curve for Colorado. Future studies should have expanded timelines and budgets to enable deeper analysis into these areas, offering a more comprehensive evaluation of transmission investment impacts and potential cost savings from avoided infrastructure projects. Stakeholders have voiced interest in additional scenario analysis, such as one with high demand *and* regional integration, further analysis of GETs and advanced transmission technologies and scenarios focused on DERs. Stakeholders also voiced interest in a study focused less on expansion plans and more on avoiding upgrades needed in the near-term horizon using grid enhancing technologies.
- **Perform Periodic Updates and Continuous Improvement.** Both stakeholders and CETA have expressed interest in exploring periodic updates to this study, with potential updates occurring every 3 to 5 years. These periodic updates would allow for the incorporation of new data, evolving market dynamics, and advancements in technology. Regular updates would also ensure that Colorado's transmission planning remains aligned with the state's evolving energy needs and policy goals, providing ongoing insights into grid improvements and investment priorities. Scenario-based planning efforts such as this one are best performed continuously as it allows for consideration of "persistence" when evaluating the need for upgrades: those upgrades identified in many planning cycles in a row are more likely to be needed and valuable to the state than an upgrade identified in a single point-in-time study.

By focusing on these areas of improvement and continued engagement, future studies can provide even more detailed insights into transmission needs, optimize resource placement, and foster a more collaborative approach to long-term grid planning in Colorado. These efforts will help Colorado meet its clean energy transition goals and maintain a reliable and efficient transmission system.

All studies have technical limitations, and this effort focused on forecasting long-range transmission gaps for the Colorado grid is no different. The following points outline several considerations that add context to the study's results and recognize limitations inherent in long-range planning activities:

- **Inherent Uncertainty in Long-Term Projections.** Twenty-year studies are inherently uncertain due to the multitude of external and uncontrollable factors that can influence outcomes. These factors include economic conditions, supply chain dynamics, policy and regulatory changes, and technological advancements. As a result, the projections and recommendations regarding transmission buildouts presented in this study should be viewed as exploratory scenarios rather than precise forecasts. However, the portfolios and concepts presented can be considered as a holistic view of the magnitude of potential transmission need.

- **Transmission Corridors.** The study did include detailed assessments of each transmission corridor to determine their ability to accommodate new lines or upgrades. Factors such as right-of-way availability, environmental constraints, and land use considerations were not exhaustively evaluated, and were explored only on a preliminary basis. Further investigation and site-specific studies will be necessary to validate the feasibility of proposed transmission projects.
- **Uncertainty in Resource Buildouts.** The addition of resources beyond a 10-year forecast through busbar mapping involves a significant degree of uncertainty and relies heavily on engineering judgment (and the views of stakeholders). The resource allocations and resulting transmission solutions identified in this study should not be considered "optimal" or "least-cost" options. Instead, they represent plausible, or in some cases likely, scenarios aimed at exploring potential future states of the grid.
- **Cost Estimates.** The costs associated with transmission infrastructure and other grid resources have changed substantially over the past five years and are likely to continue evolving. Factors such as material prices, labor costs, and technological innovations can significantly impact future expenditures. This study did not perform sensitivity analyses on cost variations, which could influence the selection and prioritization of transmission solutions.
- **Community and Landowner Engagement.** The development of significant new transmission infrastructure requires the support and collaboration of Colorado's communities and landowners. Public acceptance is crucial for the successful implementation of large-scale, greenfield transmission projects. Ongoing engagement, transparent communication, and inclusion of stakeholder input are necessary to address concerns and build consensus around infrastructure development.

Given these caveats, the findings and recommendations of this study should be interpreted with an understanding of their limitations. Future work should aim to address these uncertainties by incorporating more detailed analyses, engaging with a broader range of stakeholders, and updating assumptions as new information becomes available. By acknowledging these limitations, stakeholders can better appreciate the exploratory nature of this study and use it as a foundation for more granular planning and decision-making processes.

4. Appendices

Additional Study Information and Outreach

The purpose of this report was to highlight the core takeaways from the study. Readers have access to many more study assumptions, results, and analyses as well as webinar recordings, all available at the CETA website dedicated to the project: https://www.cotransmissionauthority.com/transmission-study

Below is access to the recordings and slide decks that provide more detail on the study.

Stakeholder Meeting #1

Slides | Recording

Stakeholder Meeting #2

Slides | Recording

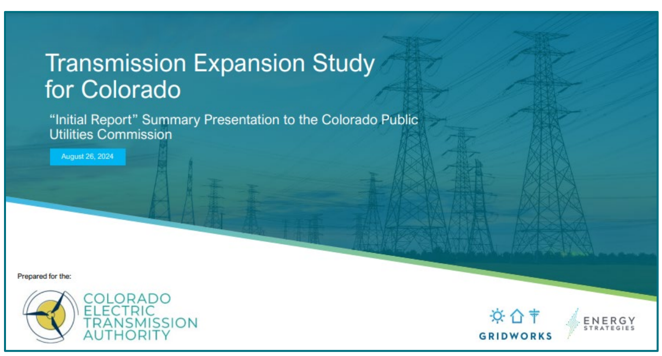
Stakeholder Meeting #3

Slides | Recording

Stakeholder Meeting #4

Slides | Recording

Colorado Public Service Commission Briefing



Slides | Recording

Participating Organizations

The following organizations either participated in stakeholder meetings and/or submitted written comments during the study's development.

Advanced Energy United	Rocky Mountain Institute
Avangrid	rPlus Hydro
BayWa r.e.	St. Vrain Technologies, LLC
Black Hills Energy	Steelhead Americas
BlueGreen Alliance	Steel Wire Solutions NA
Citizens Climate Lobby	The Nature Conservancy
CETA Board Directors	TransGrid Consulting
Climate Drift	Tri-State Generation and Transmission
CO Dept. of Regulatory Agencies	Utility Consumer Advocate
CO Public Utilities Commission	Western Area Power Administration
Colorado Energy Office	WATT Coalition
Colorado Independent Energy Association	WestConnect Planning Management Committee
Colorado Springs Utilities	West Resource Advocates
Dietze & Davis, P.C.	Xcel Energy
GBSM	Yampa Valley Electric Association
Great Plains Institute	Zim Power Solar
Grid United	
Holy Cross	
International Brotherhood of Electrical Workers	
Interwest Energy Alliance	
Invenergy	
Ireland Stapleton Pryor & Pascoe, PC	
Kaplan Kirsch	
National Audubon Society	
NextEra Energy	
Outshine Energy	
Pivot Energy	
Platte River Power Authority	

Additional Technical Materials

The following are additional technical materials not included in the Initial Report. These materials document assumptions and methods reviewed through the stakeholder process. Additional assumptions and documentation is available via the Stakeholder Meeting slide decks provided in this Appendix.

Load and Resource Trajectories

Transmission planning study results are primarily based on assumptions regarding forecasted system load and generation levels (and locations), as well as the transmission infrastructure expected to be in place for the study horizons.

One of the critical inputs to the study was a forecast of load growth over a 20-year horizon. Informed by data sourced from NREL and Colorado utility ERPs, the load forecast developed for the study's Reference Case projects Colorado peak demand of about 14 GW by 2045, up from around 10 GW in 2024. The peak demand forecast used for the study's Reference Case (e.g., business as usual) and "High Demand" Scenario are described more below. The forecasted load, among various other forecasts and constraints related to resource costs, reliability requirements, and policy goals, were input into a capacity expansion model called RESOLVE. The tool identifies optimal generation and storage investments using linear programming, adhering to reliability, technical, and policy constraints. Energy Strategies obtained, validated, and updated this model to establish a credible 20-year state-wide resource plan. For this study, RESOLVE captured a baseline resource forecast of existing, planned, and proposed generation from recent Colorado ERPs. It then identified additional generation needed after 2035, establishing a resource plan that extends beyond ERP forecasts that was suitable for a 20-year transmission planning horizon. This modeling was crucial in defining the state's future resource needs and guiding subsequent transmission assessment.

Load Forecasts

The load forecast was informed by Colorado utility ERPs and forecasts from NREL. The forecast assumed a compound annual growth rate (CAGR) consistent with the NREL Electrification Futures Study (EFS), in which NREL explored the impacts of widespread electrification, partnering with the Electric Power Research Institute, Evolved Energy Research, Lawrence Berkeley National Laboratory, Northern Arizona University, and Oak Ridge National Laboratory. The study developed three primary forecasts of future power systems electricity demand to perform its analysis: Reference, Medium, and High. The Reference electrification adoption scenario represents a business-as-usual outlook, and the Medium and High scenarios represented futures with levels of electrification beyond reference scenario to represent higher widespread electricity consumption.

Since the seed case for the 2035 CETA Reference Case powerflow model was a 2034 model from WECC, loads needed to be increased in Colorado to provide a better representation of 2035 loading. This was done by scaling appropriate loads throughout the state to achieve an overall increase of 2%, based on Colorado utility growth forecasts.

The 20-year CETA reference powerflow model utilized a CAGR of 1.87% to obtain a load level for the 2045 Reference Case powerflow model. That value is consistent with the Medium NREL EFS forecast. Therefore, the Colorado loads in the 2045 CETA Reference Case had to be increased from the 2035 case by approximately 3,100 MW.

Resources

As indicated in the report, the RESOLVE tool was utilized to develop 10-year baseline resource forecasts of existing, planned, and proposed generation, based on data gathered from Colorado ERPs. Some adjustments were made to the 10-year resource modeling, which also started from the WECC 34HS model. For example, in the WECC model, some coal-fired resources were still modeled as being in-service. All coal-fired resources were removed from the model and replaced with renewable resources. The total resource capacity modeled in the 10-year Reference Case model was approximately 30 MW, consisting of about 19 GW of existing generation, about 11 MW of planned and conceptual capacity, based on ERPs.

The Colorado electrical system was divided into nine study zones for the powerflow analysis and to help determine appropriate locations for the 20-year resources. Zone development started with the five Energy Resource Zones (ERZs) that have been defined by PSCo through their SB100 process. Busbar mapping and the RESOLVE modeling were then used to identify resources needed that would provide a least-cost means to meet long-term planning and policy goals. The process led to increasing the number of study zones to nine and provided a first cut at assigning new resources to existing and planned substations.

Transmission Cost Assumptions

There are a limited number of public transmission cost estimation tools available. The MISO cost estimation guide has proven to be one of the standards in the industry and considers all of the essential components that must be considered in the construction and implementation of transmission project facilities. These cost components include conductors, optical ground wire, and shield wire, tower structures, right-of-way, land acquisition, regulatory and permitting, engineering, environmental studies, testing and commissioning, administrative and general overhead, AFUC, and contingency percentage. MISO updates the guide on a regular basis, the most recent being the Transmission Cost Estimation Guide that it used for its 2024 MISO Transmission Expansion Plan (MTEP).

To develop costs for the projects identified in this study, the MISO guide was used as a starting point. Costs from recent Colorado utility projects were considered to ensure that there was alignment with the MISO costs and costs of projects local to Colorado.

The following tables provide general costs guidelines used for project estimates.

Table 14: Transmission Upgrade Cost Guide

Upgrade	Cost per Mile	
	230 kV	345 kV
Reconductor	$357,109	$559,960
Co-locate Circuit	$3,726,959	$6,302,473
New Single Circuit Line	$1,867,195	$3,181,128
New Double Circuit Line	$3,726,959	$6,302,473

Table 15: Transformer Upgrade Cost Guide

Upgrade	Cost Per MVA			
	69 kV	115 kV	230 kV	345 kV
69 kV	$5,606	$4,564	$5,896	$7,239
115 kV	$4,564	$6,209	$5,896	$6,880
230 kV	$5,896	$5,896	$8,444	$7,239
345 kV	$7,239	$6,880	$7,239	$10,286

Table 16: Substation Upgrade Cost Guide

Upgrade	Cost by Voltage	
	230 kV	345 kV
Add 1 Position (double-breaker bus)	$3,400,000	$5,400,000
Add 2 Position (double-breaker bus)	$6,800,000	$10,700,000
New 4 Position (double-breaker bus) substation	$15,900,000	$23,700,000

Due to the diversity of terrain in the state, Montara Mountain Energy performed an analysis of the transmission line routing to develop more granularity on the routing complexities of each project. Costs were then adjusted based on the specific geographic and environmental factors evaluated in the Montara analysis. The following table shows how terrain multipliers were applied in the routing optimization:

Table 17: Terrain Multipliers

Terrain	Multiplier
Flat	1
Rolling Hills (2-8% Slope)	1.4
Mountain (>8% Slope)	1.75
Forest	2.25
Urban	1.59
Wetlands	1.3
Agricultural land	1.1
Airfields	1.5

Terrain	Multiplier
Bodies of water (lakes, rivers)	3
Fire risk	1.2

Transmission Need & Solution Methods and Assumptions

Transmission needs and resulting proposed solutions were determined by performing both what have been referred to as "reliability" and "deliverability" analyses. These terms are used to define the general objective of the analyses, even though all studies are rooted in reliable performance. In the context of this study, the reliability analysis consisted of an evaluation of system-wide, and in this case state-wide performance. A model was developed to represent the Colorado system under peak load conditions with resources dispatched to meet load requirements without relying on importing power from adjacent regions. The deliverability analysis consisted of utilizing the nine zones developed during the busbar mapping exercise to provide additional stress by evaluating maximum resource dispatch in each zone individually.

The deliverability analysis was performed first, since it provided more insight into specific potential transmission needs. In addition to evaluating transmission needs on a zone-by-zone basis, solutions were developed, and then refined to complement inter- and intra- zone issues, as well as considering the broader state-wide system. Once potential solutions and transmission portfolios were developed, the overall reliability assessment was performed.

For all of the powerflow analyses, system performance was evaluated based on Reliability Standards set forth by NERC. In general, that entails evaluation of facility loading and voltage for both system intact and contingency (loss of a facility or facilities) conditions. For conditions where performance is outside designated criteria, system upgrades are considered and applied to mitigate the issues.

For each of the proposed portfolio projects, alternative solutions were considered and assessed before making final recommendations. This "Transmission Alternative Assessment" contemplated substitute transmission projects, construction alternatives, and non-transmission solutions. Substitute transmission projects are alternative transmission facilities that provide the same mitigation and performance, but have different physical routing or other characteristics. Construction alternatives include replacing conductors on existing lines with higher capacity conductors, and rebuilding existing lines to have more circuits and higher voltage. Non-transmission alternatives include utilizing energy storage, dynamic line ratings (DLR), and advanced powerflow controllers (APFC). Adjustments to the proposed portfolios were made based on the transmission alternative assessment.

Scenarios and Project Concepts

In addition to the Reference Case (the business-as-usual scenario), the study explored conceptual alternatives to the Reference Case Portfolio, two additional scenarios, and three options for inter-state transmission expansion.

Conceptual Alternatives

The Conceptual Alternative projects are those that can be considered expansions to the reference portfolio projects, but in some cases may be alternatives to proposed reference project segments.

Those that are expansions are primarily on the western slope of Colorado. These are projects that were developed by increasing resources on the western slope beyond what was modeled in the Reference Case. An additional 1,500 MW of generation capacity was modeled in the Northwest zone, and an additional 1,000 MW was modeled in the Southwest zone to stress the western slope transmission. The rationale for adding 1,500 MW to the Northwest zone was that even though there were 2,150 MW of new resources added, the retirement of Craig and Hayden coal plants reduced the generation in that zone by over 1,500 MW. The Southwest zone had the lowest incremental generation added at 900 MW, and has significant transmission in the area. Therefore, the conceptual study added an additional 1,000 MW. Those increases led to the concept of adding an additional 345 kV circuit from Craig to Four Corners. In order to deliver that power to the Front Range load centers, 345 kV transmission was proposed from Montrose to Poncha. The Reference Case Portfolio segment of 345 kV transmission from Poncha to Midway provided the delivery to the Front Range.

The conceptual projects on the eastern plains of Colorado are generally alternatives to Reference Case Portfolio projects. Some of these were projects that were initially proposed before performing the Transmission Alternative Assessment, and are for the most part, higher cost alternatives to those proposed. However, there may be instances where these alternatives could still provide advantages and be constructed in addition to the proposed Reference Case Portfolio projects. An example is the Lamar to Gladstone segment, which would provide additional reliability benefits, as well as enable interstate transfers into New Mexico.

Scenarios

The scenarios were meant to evaluate alternate futures from the business-as-usual Reference Case. The two scenarios were chosen based on stakeholder feedback, and included a High Demand scenario that contemplates a future where there is a significantly higher consumption of electricity from sources such as data centers, electric vehicles, and hydrogen production. The other scenario selected was the Regional Integration scenario that evaluated how expanding transmission between Colorado and the SPP could assist with meeting clean energy goals.

High Demand

The High Demand Scenario assessment began with developing a load forecast based on higher state-wide electrification. Capacity expansion modeling indicated a peak load increase of an additional 7 GW on top of the Reference Case. Only solar, BESS, and gas/clean firm resources were added. The following table shows where the resources were added. Solar resources were located based on the busbar mapping methodology, and the additional firm and solar resources were located at locations that already had those resources.

Table 18: Resource Placement for High Demand Scenario

	Solar		Gas (or clean firm)		BESS		Total
Zone	**MW**	**Bus**	**MW**	**Bus**	**MW**	**Bus**	
North Central	170	Husky	500	Rawhide	100	Husky	
			300	St. Vrain	50	Ft. St. Vrain	
			200	Ft. Lupton			
Zone Total	170		1000		150		1320
Northeast	0		1000	Pawnee	50	Pawnee	
Total	0		1000		50		1050
South Central	300	Sandstone	500	Comanche	150	Sandstone	
Zone Total	300		1000		150		1450
SLV	200	San Luis	0		50	San Luis	
Zone Total	200		0		50		250
Northwest	200	Craig	1000	Craig	100	Craig	
Zone Total	200		1000		100		1300
Southwest	200	Montrose	1000	Montrose	100	Montrose	
Zone Total	200		1000		100		1300
TOTAL (Increment)	**1070**		**5000**		**600**		**6670**

Adding an additional 7 GW to the Reference Case presented several challenges from a powerflow solution perspective. As expected, the Reference Case portfolio of projects was not sufficient to deliver the additional resources. Second, the increase in load required significant addition of voltage support throughout the system. As with the Reference Case study, both reliability and deliverability assessments were made. However, for the High Demand Scenario, significant upgrades were needed for the reliability model before the deliverability assessment could be performed. About $3.8 billion of upgrades were required to achieve acceptable performance for the reliability case. Significant upgrades included over 1,100 miles of reconductoring, almost 200 miles of new 115 kV lines, almost 250 miles of 115 and 230 kV rebuilds, and implementing the conceptual 345 kV transmission on the western slope. The deliverability assessment resulted in an additional $440 million of upgrades.

The overall result was that over $4 billion of network upgrades were required for the High Demand Scenario, which is double the cost of the Reference Case Scenario.

Regional Integration

The Regional Integration Scenario assessment was performed to understand how integration between SPP and WECC, and specifically to the eastern edge of Colorado, might impact the Reference Portfolio. Three alternatives were evaluated to examine the impact of a 2,000 MW transfer into eastern Colorado. Various methodologies were contemplated for this analysis. One was to simply displace the 2,000 MW coming from SPP by reducing eastern Colorado generation by the same amount. However, that would not provide any useful insight, since the Reference Portfolio could handle that dispatch. Another was to inject all 2,000 MW in addition to the generation in the Reference model. However, that would likely be too extreme, since the system would not likely be operated in that manner. The methodology chosen was a compromise that dispatched the 2,000 MW into mostly western zones of the state, thereby providing a more reasonable level of stress to the eastern Colorado system. The assessment assumed that the SPP power could be injected at existing Colorado substations of Lamar, Burlington, and Sidney. These locations have existing back-to-back DC ties. An important caveat is that this scenario study did not evaluate the costs of upgrading the back-to-back DC ties. The present capacities of the ties are 200 MW or less. It is uncertain how much it would cost to increase that capacity by up to ten times that level.

Three alternatives injection patterns were evaluated:

- 2 GW injected at Lamar
- 1 GW injected at Lamar and 1 GW injected at Burlington
- 1 GW injected at Lamar and 1 GW injected at Sidney

Each of the concepts required transmission upgrades west of Lamar. Somewhat surprising was that the alternative with the full 200 MW injected at Lamar was the lowest cost alternative.

As noted in the report, study did not assume an assessment of expanding HVDC Tie capability to enable this transfer. The DC Tie Expansion Task Force of the CCPG released a study report in 2024 that summarized studies of expanding existing HVDC ties. The report indicated costs of $300 - $900 million for new converter stations that could provide up to 1,000 MW of capability.