# 20-YEAR CONCEPTUAL SCENARIO REPORT

## For the State of Colorado

To comply with

**Rule 3627**
**of the**
**Colorado Public Utilities Commission**
**Rules Regulating Electric Utilities**

February 1, 2018

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## ACRONYMS AND ABBREVIATIONS

| **Acronym or Abbreviation** | **Term** |
|---|---|
| 2018 Scenario Report | 2018 20-Year Scenario Analysis Report |
| BES | Bulk Electric System |
| BHCE | Black Hills Colorado Electric Utility Company, L.P. |
| Black Hills | Black Hills/Colorado Electric Utility Company, L.P. |
| CCPG | Colorado Coordinated Planning Group |
| Commission or CPUC | Colorado Public Utilities Commission |
| Companies | Black Hills, Tri-State and Public Service |
| Company | Black Hills, Tri-State or Public Service |
| CPCN | Certificate of Public Convenience and Necessity |
| CPP | Clean Power Plan |
| CPWG | Conceptual Planning Work Group |
| DER | Distributed Energy Resources |
| DG | Distributed Generation |
| EIM | Energy Imbalance Market |
| EPA | Environmental Protection Agency |
| FERC | Federal Energy Regulatory Commission |
| HVDC | High Voltage Direct Current |
| IOU | Investor Owned Utility |
| ISO | Independent System Operator |
| kV | Kilovolt |
| MW | Megawatts |
| MWTG | Mountain West Transmission Group |
| NECO | Northeast Colorado |
| Public Service or PSCo | Public Service Company of Colorado |
| PV | Photovoltaic |
| RES | Renewable Energy Standard |
| RTO | Regional Transmission Operator |
| SPP | Southwest Power Pool |
| SB07-100 | Colorado Senate Bill 07-100 |
| SCADA | Supervisory Control and Data Acquisition |

| Acronym or Abbreviation | Term |
|---|---|
| SWEP | Southwest Weld Expansion Project |
| TP | Transmission Provider |
| Tri-State or TSGT | Tri-State Generation and Transmission Association, Inc. |
| WECC | Western Electricity Coordinating Council |

# I. Executive Summary

Rule 3627, which was adopted by the Colorado Public Utilities Commission ("CPUC" or "Commission") in 2011, requires the preparation and biennial submission of 10-year transmission plans and conceptual long-range scenarios that consider a 20-year transmission planning horizon. The first 10-Year Transmission Plan was submitted jointly by Black Hills/Colorado Electric Utility Company, L.P., d/b/a Black Hills Energy ("Black Hills"), Public Service Company of Colorado ("Public Service" or "PSCo"), and Tri-State Generation and Transmission Association, Inc. ("Tri-State" or "TSGT") (each referred to individually as a "Company" and collectively as the "Companies") on February 1, 2012. In 2012, the Companies were not required to submit 20-year conceptual scenarios. The first 20-Year Conceptual Scenario Report was filed in 2014 and the second Report was filed in 2016. This 2018 20-Year Conceptual Scenario Report ("2018 Scenario Report") has been jointly prepared and is being submitted by the Companies.

Scenario-based analysis is a technique for considering uncertainties that may impact decision-making in today's world based on potential future conditions. It may be useful when evaluating long-term investments despite the inability to accurately predict future conditions. While it is impossible to predict the future with complete accuracy, scenario development can assist with the identification of strategic choices that utility planners, project developers, regulators, and advocates may reasonably need to consider over a 20-year time period.

The scenarios offered in this filing include two provided by Black Hills, four from Tri-State, and three from Public Service. The Companies' scenarios generally address what the future state of the transmission system might look like in Colorado based on the occurrence of different factors or events, including changes in generation mix, load growth, load demand, social, economic, generation technology, transmission assumptions, and changing public policy requirements.

In addition to the Companies' scenarios, the Colorado Coordinated Planning Group ("CCPG") evaluated a scenario through the Conceptual Planning Work Group ("CPWG"). As with all CCPG activities, the CPWG was open to all interested stakeholders.

## II. Overview of the Colorado 20-Year Conceptual Scenarios Analysis

On March 23, 2011, the Commission issued its Order on Exceptions (Decision No. C11-0318) in Docket No. 10R-526E, "In the Matter of the Proposed Rules Related to Electric Transmission Facilities Planning, 4 Code of Colorado Regulations 723-3." Pursuant to that Order, the Commission adopted Rules 3625 through 3627 pertaining to the coordinated planning for additional electrical transmission facilities in Colorado.

Rule 3627 requires the preparation and biennial submission of 10-year transmission plans and conceptual long-range scenarios that consider a 20-year transmission planning horizon. The first 10-Year Transmission Plan was submitted jointly by the Companies on February 1, 2012. When the Commission adopted Rule 3627, it was decided that the first filing should only include the 10-year transmission plan. The first 20-year conceptual scenarios were submitted in 2014 with the subsequent report scenarios submitted in 2016.

Scenario-based analysis is a technique for considering uncertainties that may impact decision-making in today’s world based on potential future conditions. It may be useful when evaluating long-term investments despite the inability to accurately predict future conditions. Although it is not possible to predict the future with complete accuracy, scenario development can assist with the identification of strategic choices that utility planners, project developers, regulators, and advocates may reasonably need to consider over a 20-year time period.

The 2018 Scenario Report identifies and assesses various credible future alternatives and provides information that can be used individually or in conjunction with utilities, coordinated planning organizations, lawmakers, and other industry stakeholders to further evaluate the ongoing transmission needs in the State of Colorado. These scenarios describe a set of economic, technological, and societal circumstances that the Companies believe could conceivably come to pass.

Consistent with the requirements of Rule 3627(e), the Companies’ conceptual scenarios discussed herein include, at a minimum:

- reasonably foreseeable future public policy initiatives;

- possible retirement of existing generation due to age, environmental regulations, or economic considerations;
- emerging generation, transmission, and demand limiting technologies;
- various load growth projections;
- studies of any scenarios requested by the Commission in the previous biennial review process; and
- changes in market conditions.

With respect to reasonably foreseeable future public policy initiatives, in addition to the public policy requirements of Colorado Senate Bill 07-100 and the present and potentially evolving requirements of Colorado's Renewable Energy Standard, all three Companies may be subject to federal and Colorado regulations related to carbon emission reductions from existing power plants. The U.S. Environmental Protection Agency's ("EPA") previously proposed Clean Power Plan ("CPP"), which was finalized in late-2015, never went into effect and the EPA has stated that it intends to replace the CPP with new rules. Similarly, no Colorado CPP compliance plan has been developed. In the event that EPA issues new carbon emission reduction rules for the electric power sector, the requirements of those rules and any associated Colorado compliance plan or separate Colorado carbon emission reduction plan may become a driver for consideration in future scenarios for the Colorado transmission system. The Companies will continue to monitor developments related to federal and Colorado carbon emission reduction initiatives and may address this scenario in the next 20-Year Conceptual Scenario Report.

## III. Company Perspectives on Conceptual Scenarios Analysis

### A. Black Hills

Black Hills recognizes the potential for 20-year conceptual planning to contribute to the development of 10-year transmission plans. While not all utilities and planning organizations will always agree about whether a particular future scenario is probable or realistic, simple consideration of the impacts of any and all given scenarios can only add value to each Company's planning process. One distinction that sets Black Hills apart from some other entities in Colorado is that, as an electric utility under the jurisdiction of both the Federal Energy Regulatory Commission ("FERC") and the Colorado Commission, we must consider potential future federal and/or public policy initiatives that may not directly impact other entities. When considering the large number of potential future scenarios for this report, Black Hills also had the opportunity to explore and draw on the implications of various driving factors experienced by its sister electric utilities in Wyoming and South Dakota.

It is Black Hills' view that much of the planning work that has been previously performed within the various utilities and regional planning groups and reported in the preceding Rule 3627 20-Year Scenario reports generally suggest transmission development to enhance reliability and connect planned and potential resources located along the southern and eastern part of Colorado to the Denver area load center. There are identified transmission projects that align with this trend, such as the Rush Creek project and the Lamar-Burlington project. The magnitude and timing of future transmission expansion, as well as the degree of participation from utilities and other entities, could be driven by any combination of drivers mentioned in Rule 3627(e).

For the purposes of this filing, Black Hills considered scenarios that are variations of those included in the previous filings as well as new scenarios unique to this filing. The scenarios described below were selected by contemplating scenarios that provided dissimilar yet significant impacts to the transmission system while remaining plausible. There are no specific transmission plans associated with the scenarios described herein, but rather a general discussion of potential impacts and considerations.

**Black Hills Scenarios**

Included below is a brief summary of each of the scenarios explored by Black Hills. Full descriptions, including rationale, drivers and assumptions behind each scenario, can be found in Appendix A.

***BHCE Scenario #1: BES Impacts Due to Severe Disruptions on the Natural Gas System***

This scenario recognizes the increased prevalence of gas-fired generation and the impacts to the Bulk Electric System (BES) that may arise due to complications with the gas infrastructure. This scenario was explored in a 2017 Special Reliability Assessment[1] published by NERC. Electric transmission system planners should evaluate scenarios that consider widespread loss of gas generation due to single point of failure events on the natural gas supply system as appropriate.

***BHCE Scenario #2: Significant Increase in End-Use Electrification***

The scenario explores the impacts of substantial demand growth across the system as well as a more pronounced demand peak due to widespread electrification of end-use processes such as manufacturing and transportation. This load growth would be pervasive across the state but particularly disruptive in urban areas, creating challenges in reliably delivering energy to meet the demand but also managing potentially problematic power quality or stability issues. Peak demand growth as well as consumption pattern changes in areas of probable load development should be considered in transmission planning assessments and incorporated into transmission expansion plans as appropriate.

## B. Tri-State

Tri-State brings a unique perspective to the 20-year conceptual scenario planning process under Commission Rule 3627(e). While Black Hills and Public Service are investor-owned, vertically integrated electric utilities providing retail electric service in Colorado, Tri-State is a not-for-profit, generation and transmission cooperative providing wholesale electric power to its 43 Member Systems located in four states: Colorado, Nebraska, New Mexico, and Wyoming.

Unlike Black Hills and Public Service, Tri-State is a regional power provider and its transmission system is designed and operated without specific regard to individual state boundaries. Rather, Tri-State operates an integrated, interconnected, interstate transmission system to deliver reliable, affordable, and economic power to its Member

[1] See the November 2017 NERC Report: "*Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*."

Systems. There are also generation resource differences that influence Tri-State's long-range conceptual transmission scenario perspectives, as compared to other utilities. Tri-State's generation resources are located in Colorado, New Mexico, Wyoming, and Arizona and require an interstate transmission system that efficiently moves that power to its Member Systems in Colorado and elsewhere.

In addition to these fundamental differences in transmission system and generation resource considerations, Tri-State faces other considerations that are the same or similar to those that apply to Black Hills and Public Service including compliance with Colorado's Renewable Energy Standard, dynamic market forces, a changing resource mix driven by federal and state public policy developments, and expanding deployment of distributed generation and other technologies.

Tri-State's view of the long-range conceptual future is not limited to possible developments in Colorado and must consider the load-serving, reliability, economic, social, and technological needs of all of its Member Systems and the states in which they are located. All of these considerations influence Tri-State's conclusions with respect to what may constitute "credible alternatives" for purposes of 20-year conceptual scenarios.

Tri-State's 2018 conceptual scenarios are summarized below. Full descriptions, including rationale, drivers and assumptions behind each scenario, can be found in Appendix B.

## Tri-State Scenarios

In developing its scenarios for inclusion in the 2018 Rule 3627 filing, Tri-State considered key public policy, industry, and technology drivers that are likely to influence – possibly to a significant degree – the operation and evolution of Colorado's transmission system over the course of the next 20 years.

Drivers identified in 2018 have many similarities to those discussed in Tri-State's 2016 20-Year Conceptual Scenarios. The carbon reduction scenario discussed in 2018 Scenario 1 bears some similarity to 2016's Scenario 3 – Changing Generation Resource

Portfolio in Response to Clean Power Plan, but has been updated to reflect the fact that federal greenhouse-gas reduction policies are presently uncertain. Inclusion of Colorado in an organized electricity market (2018 Scenario 2) is consistent with the regional interconnections discussed in Tri-State's 2016 Scenario 1 with updates to recognize recent developments. Likewise, the increasing role of distributed generation resources discussed in 2018 Scenario 3 is consistent with a similar discussion in the 2016 Scenario 2. 2018 Scenario 4, Increased East-West Interconnection, was not expressly discussed in the 2016 20-Year Plan, and is being included this year to reflect new possibilities related to such interconnection that flow from the Mountain West Transmission Group's investigation into joining an organized market.

***TSGT Scenario #1: Carbon Reduction Requirements***

While the federal Clean Power Plan now appears unlikely to be implemented as originally proposed, carbon regulation at the state and regional level remains a reasonably foreseeable possibility and is appropriate to consider in this Report. It is not currently clear exactly what form such carbon regulation might take. Nevertheless, it is realistic to assume that any such regulation, should it become applicable, would likely result in decreased use of high carbon-intensity resources such as coal-fired generation, and increased use of lower carbon-intensity resources such as natural gas and renewable generation. Given the location of existing high carbon intensity electric generating units and the locations of Colorado's renewable resource generation development areas, such a change in Colorado's generation resource portfolio may require improvements and additions to Colorado's transmission system to ensure its continued reliability and to deliver resources to load centers.

***TSGT Scenario #2: Organized Markets***

The Mountain West Transmission Group ("MWTG"), which includes Tri-State, is currently investigating the possibility of joining an organized electricity market such as the Southwest Power Pool ("SPP"). While that process has not yet reached a conclusion, it is reasonably foreseeable that the MWTG process could result in the MWTG utilities joining an organized market. This scenario considers the impacts and benefits to the Colorado transmission system that could result from membership in an organized market.

***TSGT Scenario #3: Increased Role of Distributed Energy Resources***

Distributed Energy Resources ("DER") continue to play an increasing role in Colorado's energy mix. This scenario focuses on the growth of distributed energy technologies such as solar Photovoltaic ("PV") generation, advancements in energy storage, and increased interest in and deployment of other distributed resources such as community wind, geothermal, biomass, small and micro hydropower, coal mine methane, synthetic gas produced by pyrolysis of municipal solid waste, and recycled energy, as well as associated public policy developments. This scenario assumes continued and significant advancement and growth of such resources coupled with low load growth and higher efficiency, and considers the potential impact of such resources on the transmission system.

***TSGT Scenario #4: Increased East-West Interconnection***

This scenario focuses on increased coordination and transfer capabilities between the Eastern and Western Interconnections. This scenario is related to the Organized Market scenario discussed above and focuses specifically on the potential for new DC-Tie facilities, improvements to existing DC-Tie facilities, and the construction of new DC transmission lines.

## C. Public Service

Public Service, one of four utility-operating company subsidiaries of Xcel Energy Inc., is an investor-owned utility ("IOU") serving approximately 1.4 million electric customers in the State of Colorado. Public Service serves approximately 75% of the State's population. Its electric system peaks in the summer with a 2016 peak customer demand of 6,665 Megawatts ("MW"). The entire Public Service transmission network is located within the State of Colorado and consists of approximately 4,500 circuit-miles of transmission lines. Colorado is on the eastern edge of the Western Electricity Coordinating Council ("WECC") region, also referred to as the Western Interconnection, which operates asynchronously from the Eastern Interconnection. The Public Service transmission system has been interconnected with the transmission system of another Xcel Energy operating company, Southwestern Public Service Company, since December 31, 2004 via a jointly-owned tie line with a 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station. The Public Service retail service territory includes the Denver-Boulder metro area, as well as the I-70 corridor to Grand Junction, the San Luis Valley, Greeley, Sterling, and Brush.

Public Service participates in CCPG, WestConnect, and WECC planning forums, including the subcommittees and working groups that perform transmission scenario analyses. Scenario outlooks differ from 10-year transmission analyses because the number of unknown factors to consider increases significantly with each year into the future. While 10-year plans tend to identify specific or conceptual transmission projects, the longer-term scenario analysis generally results in narrative descriptions of what major drivers to the power supply market might look like from a transmission perspective in the future. These drivers include generation mix, load growth, load demand, transmission assumptions, and pending public policy requirements. Potential impacts to the transmission system are not described in terms of specific projects, but by conceptual descriptions of different drivers and scenarios that may impact transmission.

Scenario investigation can be informative to decision makers, especially during times of high uncertainty and risk as a result of factors such as pending environmental legislation, changes in penetration of renewable energy mix, and changes in efficiency standards. In the utilities industry, 10-year transmission planning analysis is sometimes referred to as "just-in-time planning" because the average time to analyze, site, permit, and construct transmission facilities to meet a known need is approximately 7-10 years. Longer-term scenario analyses can help provide indicators and drivers that could prompt changes in the transmission solutions. This allows decision makers to make better-informed decisions for long-term based assets.

Public Service believes that conceptual scenario analysis also has the ability to help transmission planning and generation planning to become better integrated. One possibility would be to encourage the generation resource planning process to establish an identified resource need including possible resource costs and locations, and available transmission capacity for a period of 15 to 20 years into the future. In addition, resource plans that utilize the results of a competitive bidding process may help identify the general differences in cost between generation plans and their associated transmission expansion plans and cost. Likewise, transmission planners would be informed by the projected generation in the resource plans as a means to develop transmission expansion alternatives that could provide transmission access for various generation options.

Currently parallel schedules for joint transmission and generation projects within the 10-year planning horizon help protect capital investments worth hundreds of millions of dollars, since one of the most significant drivers of these projects is cost. However, for an integrated transmission and generation process to succeed in planning alternatives and projecting resource costs and locations out 20 years, price sensitivities may not be able to drive all studies to the extent they do in the shorter term.

Public Service continues to be involved in regional energy market development in the Western Interconnection as a means to improve management of conventional and variable energy resources. Some studies have been conducted to identify the benefits of regional markets through stakeholder proceedings by WECC, evaluations of an Energy Imbalance Market ("EIM") by the Western Interstate Energy Board, as well as sub-regional studies including those of the Northwest Power Pool. Public Service's stance on regional markets is based on the following factors: 1) pooled balancing obligations create a diversity benefit and reduced ramping requirements; 2) improved transmission asset utilization can be attained through security-constrained economic dispatch; and, 3) potential reduction in required capacity margin assures resource adequacy. The issues around consolidated tariff administration for transmission access associated with the regional market remain unresolved at this time.

**Public Service Long-Term View**

Public Service continues to be interested in the future scenarios that were described in the 2016 Scenario Report. Because potential future scenarios are numerous, and due to the uncertainties mentioned above, the long-term view of the build-out of the State's transmission system is uncertain. However, when looking at the results of the CCPG and past WECC scenario analyses, some common themes emerge. One is the potential for a transmission network that connects eastern Colorado to the Front Range load centers. Both the CCPG and past WECC scenarios indicate such a system may be necessary, if drivers emerge such as an increased requirement for renewable resources, or if a compelling reason arises to export power to other regions. The Lamar-Front Range Transmission Plan could play a role in facilitating those needs. However, Public Service also sees a potential for cost-effective resource development in northeast Colorado as compared to southeast parts of the State. As a result, the Company has moved forward with the Pawnee – Daniels Park Project rather than what has been proposed in the Lamar-Front Range plan.

## Public Service Scenarios

In the planning cycle leading to the 2014 and 2016 20-Year Conceptual Scenario Reports, Public Service contemplated four possible scenarios. Those included:

1. Regional Market Dispatch
2. Significant Load Growth Associated with Oil & Gas Development
3. High Penetration of Distributed Generation

These are scenarios that remain of interest to Public Service; as a result, Public Service is providing updates on how each of these have actually started to impact the Company.

### *PSCo Scenario #1: Regional Market Dispatch*

This scenario contemplates the development of a large-scale regional market within the Western Interconnection that assumes a least-cost interconnection-wide dispatch with transmission solutions. This scenario assumes the development of an energy market across the interconnection that dispatches the least-cost generation across the least-cost transmission expansion needed to serve load. The MWTG is a coalition of 10 electricity service provider, including Public Service, representing approximately 6.4 million customers and 16,000 miles of transmission line primarily in the U.S. Rocky Mountain Region. MWTG began discussions in 2013 to evaluate a suite of options ranging from a common transmission tariff to membership in an existing Regional Transmission Operator ("RTO"). Extensive analyses indicated that RTO membership and market participation would provide greater benefits to customers than a common tariff alone.

In September 2017, the MWTG announced that it has completed initial discussions with the SPP management team, concerning membership in the SPP regional transmission organization. Through these discussions, Mountain West has determined that membership in SPP would provide opportunities to reduce customer costs, and maximize resource and electric grid utilization. Integration into SPP, if pursued by the group, could occur as soon as late 2019. While MWTG remains optimistic that an RTO would benefit its entire membership, each Mountain West participant will ultimately need to individually evaluate whether potential membership benefits its customers. Each will pursue regulatory or governing body approval, as applicable.

Note that this scenario is similar to Black Hills Scenario #1 and Tri-State Scenario #1.

***PSCo Scenario #2: Significant Load Growth Associated with Oil & Gas Development***

This scenario contemplates pockets of the Public Service service territory that have the potential for high customer load growth associated with oil and gas exploration and development. These include Northeast Colorado and the Western Slope.

As it turns out, in the last few years, companies have been drawn to Northeast Colorado in search of oil and natural gas from the Niobrara Shale Formation. Load-serving entities such as Public Service and Tri-State have recognized the potential for increased demand for electricity due to oil and gas development. Public Service is also interested in ensuring reliability for its customers in the region, including the City of Greeley. Greeley is served by aging 115 kilovolt ("kV") and 44 kV transmission networks, and needs to ensure that the transmission system is planned and upgraded to accommodate reliability and load growth needs into the future. Therefore, the Public Service has focused a significant portion of its planning on the development of a coordinated transmission plan for northeast Colorado. Public Service is considering participating in the Tri-State Southwest Weld Expansion Project ("SWEP"), which will initiate the transmission development in the region for serving oil and gas loads. The SWEP consists of 230 kV and 115 kV transmission that begins near Ft. Lupton, Colorado, travels east towards Hudson, and then heads north and ultimately connects to existing transmission a few miles south of Kersey. Tri-State received a Certificate of Public Convenience and Necessity ("CPCN") for the project from the Commission in 2014. Much of the SWEP transmission is planned to be constructed as double-circuit with 230 kV capability, with one circuit initially energized at 115 kV.

The Weld – Rosedale– Milton 230 kV transmission project could be an extension of the SWEP transmission that would allow Public Service to serve its own requests for oil and gas load service in the region, allow reliability improvements to the southern Greeley transmission system, and facilitate longer-term transmission plans in northeastern Colorado. The Weld County Expansion planning effort includes the projects mentioned above, and may also include additional high-voltage transmission plans for the northeast Colorado region which could facilitate load growth, improve reliability in and around Greeley, provide access to potential resources in the region, and complement longer-term transmission projects in northeast Colorado. Public Service is working through the CCPG to develop these coordinated transmission plans.

***PSCo Scenario #3: High Penetration of Distributed Generation***

This scenario contemplated a future where distributed generation ("DG") would serve a significant portion of utility load, which could result in a reduced need for transmission expansion. Although this scenario could potentially slow the investment of new transmission development, transmission may be necessary to address other drivers and changes in energy delivery. This scenario continues to be of interest to Public Service. It is important to note that in the last few years, Public Service has implemented over 200 MW of DG on its system through community solar programs such as Solar Rewards and Solar Gardens and expects to continue to add DG in the coming years.

## IV. Colorado Coordinated Planning Group Scenario

The CCPG is a sub-regional group of WestConnect that includes transmission providers ("TPs") within the Rocky Mountain region and is open to stakeholder participation. Formed in 1991, the CCPG cooperates with state and regional agencies to assure a high degree of reliability in joint planning, development, and operation of the high voltage transmission system. The CCPG established the CPWG in the summer of 2010 to evaluate longer-term transmission studies, considering a 20-year planning horizon. Previous Rule 3627 Scenario Reports documented three scenarios that were evaluated by the CPWG. In the last two years, the CPWG focused on what was originally Scenario #3, which contemplated how present Renewable Energy Standard ("RES") in Colorado might impact transmission development in the future.

The CPWG created transmission models that reflected the 2038 horizon. Both heavy and light models were developed based on feedback from CCPG participants. The models assumed a 2038 RES of 30% for Public Service and Black Hills, 20% for Tri-State, and 10% for all other utilities. The light model reflected approximately 55% of the load that was in the peak model. Wind generation was modeled at 20% of capacity for the peak case and 80% for the light case. These models may be used by interested stakeholders to perform conceptual analyses. The CPWG performed a cursory study to evaluate the transmission system assuming all three Comanche coal-fired generation units would be retired. The results of the study indicated that the transmission system of Colorado may be adequate for the retirement of Comanche 3 by year 2038. In order to draw a definite conclusion, more studies such as transient stability and voltage stability will need to be done.

The CCPG CPWG year 2038 Study is included as Appendix D.

The 2038 and previous year reports can also be found at:

http://regplanning.westconnect.com/ccpg_conceptual_planning_wg.htm

# 2018 Scenario Analysis Appendices

# Appendix A

# Black Hills Scenarios

## Black Hills Scenario #1: BES Impacts Due to Severe Disruptions on the Natural Gas System

### *1. Description*

This scenario considers potential impacts of pursuing the development of electric and gas infrastructure without coordinating on the risks of large-scale outage events in the planning stage. Present and future public policy initiatives may continue a shift from coal to natural gas as a fuel source for dispatchable generation. Significant levels of generation loss under peak demand conditions due to a single initiating event could result in substantial power outages if the electric transmission system is not planned for such an event.

### *2. Rule 3627 (e) Application*

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | X |
| (III) | Emerging generation, transmission and demand limiting | X |
| (IV) | Various load growth projections | |
| (V) | Requested by Commission | |

### *3. Assumptions and Drivers*

- Public policy initiatives coupled with relatively low natural gas prices drive expansion of natural gas-fired generation, particularly near existing gas supply infrastructure.

- Natural gas generation plays an increasing role in offsetting the variability of non-dispatchable renewable resources, but competing demands on the gas supply exist for heating, transportation, manufacturing, etc.

- Due to the difficulty of on-site storage of natural gas in quantity, a robust real-time delivery network is key to maintaining gas-fired generation availability, especially during times of peak demand on the electric system.

## 4. ***Indicators***

- In 2017, CO Governor Hickenlooper committed the state to meet or exceed the emissions reduction targets outlined in the Paris Climate Accord, independent of current US federal government actions. This indicator enables some of the circumstances contributing to this potential future scenario.

- Coal-fired generating facilities continue to be retired across the country, changing the generation fleet diversity, giving natural gas-fired generation a larger 'piece of the pie.'

- A pre-determined threshold for electric system impacts is exceeded based on the level of natural gas-fired generation subject to a single fuel supply failure.

## 5. ***Potential Benefits and Transmission Impacts to Colorado***

There are potentially significant negative impacts of this scenario if unaddressed. A regional unavailability of generation under peak demand conditions could result in substantial load loss for electric customers, especially if electric transmission facilities are simultaneously unavailable.

This is a low probability, high impact event. The evolution of the electric and gas infrastructure does not happen quickly, and there is time to evaluate and plan to avoid a catastrophic situation.

Electric transmission plans should consider simultaneous outages of all gas-fired generators exposed to a large-scale fuel supply outage. Fuel supply diversity should be considered for future generation development in constrained areas. Coordination between electric and gas transmission planners as well as resource planners should identify the appropriate level of centralized gas-fired generation for a particular area or fuel supply source. Strategic networking of future backbone electric and gas transmission facilities can be performed in a manner that minimizes disruption to customers under such an extreme event.

# Black Hills Scenario #2: Significant Increase in End-Use Electrification

## *1. Description*

This scenario considers a significant increase in the development of customer loads distributed across the system due to widespread conversion of end-use processes to be electric-driven. As emission reduction targets from the power sector are achieved, a shift in focus to other areas such as transportation and industrial processes is likely to occur. While this could place an immediate burden on the distribution system infrastructure as well as system operators, there are also risks to be considered for the transmission system.

A driver for this scenario is a proliferation of renewable energy resources coupled with the retirement of carbon-based generation, which has the potential to present its own set of issues related to voltage deviations, etc. that could be particularly problematic on weaker parts of the transmission and sub-transmission system.

This scenario could be evaluated at a high level through the evaluation of an increased load forecast scenario in planning assessments, assuming minimal dispatchable thermal generation online.

## *2. Rule 3627 (e) Application*

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | X |
| (III) | Emerging generation, transmission and demand limiting | X |
| (IV) | Various load growth projections | X |
| (V) | Requested by Commission | |

## *3. Assumptions and Drivers*

- Emerging technologies and purchase incentives make EV ownership (with residential charging) more financially practical and broadly desired.

- Technological advances in heat pump technology, coupled with subsidies, provide an attractive alternative to carbon-based airspace heat sources for residential and commercial applications.

- Carbon-free electricity development, taking advantage of available tax credits, outpaces RES compliance needs in a centralized energy market environment. The replacement of fossil fuel based energy pushes industries to decarbonize their processes. Various aspects of the production process, i.e. energy-to-heat, become electrified, driven by public policy related to emissions reductions as well as economic benefits from a surplus in a low-carbon energy supply.

## 4. *Indicators*

- One primary indicator of pending EV adoption increases would be reaching parity on the price point between EV and traditional vehicles in Europe. Investment bank UBS has predicted this to occur in Europe as early as 2018, with the US lagging by approximately 7 years. Price parity in Europe could provide a leading indication of demand increases from EV and residential charging infrastructure.

- Technological advances allowing residential heat pumps to effectively provide heat in colder temperatures, and heat pumps becoming a more cost-effective source for central heating than natural gas would be indications of a pending increase in residential demand due to electrification of home heat sources.

- Public policy initiatives aimed at carbon reduction in the manufacturing industry, coupled with a surplus in available installed generation capacity would be a prime indicator of expected increases in electric demand within the commercial and industrial sectors.

## 5. *Potential Benefits and Transmission Impacts to Colorado*

Significant distributed demand growth can have an impact on the local and regional transmission system. If load assumptions used in planning assessments underestimate the demand, it can materially alter transmission plans of any size. Not only are capacity and voltage issues of concern, but another consideration is the loss of life impacts to transformers. Extensive EV charging under peak conditions impacts the capacity of the electric grid. Alternatively, off-peak charging may result in prolonged periods of increased transformer temperatures rather than the typical cool-down period. If not designed properly to operate in these conditions, transformer loss of life could result. The strategic time-of-use concept could also be applied to certain industrial processes to help reduce peaks and increase local aggregate load factors.

Extensive adoption of EVs may offer benefits to the electric system in the form of distributed energy storage. Advances in technology as well as public policy will dictate the extent of the benefits offered by EVs in terms of energy storage.

As transmission plans are developed, there should be close coordination with utility and industry stakeholders to ensure appropriate load assumptions are considered in planning studies.

# Appendix B

# Tri-State Scenarios

## TSGT Scenario #1: Carbon Reduction Requirements

### 1. Description

While the federal Clean Power Plan now appears unlikely to be implemented as originally proposed, carbon regulation at the state and regional level remains a reasonably foreseeable possibility and is appropriate to consider in this Plan. It is not currently clear exactly what form such carbon regulation might take. Nevertheless, it is realistic to assume that any such regulation, should it become applicable, would likely result in decreased use of high carbon-intensity resources such as coal-fired generation, and increased use of lower carbon-intensity resources such as natural gas and renewable generation. Given the location of existing high carbon intensity electric generating units and the locations of Colorado's renewable resource generation development areas, such a change in Colorado's generation resource portfolio may require improvements and additions to Colorado's transmission system to ensure its continued reliability and to deliver resources to load centers.

### 2. Rule 3627(e) Application

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | X |
| (III) | Emerging generation, transmission and demand limiting technologies | X |
| (IV) | Various load growth projections | X |
| (V) | Scenarios Requested by Commission in 2016 biennial review process | |

### 3. Assumptions and Drivers

Colorado Executive Order D2017-015, signed on June 11, 2017, declared that it is the goal of the State of Colorado to achieve an electricity sector specific carbon dioxide reduction of 25 percent below 2012 levels by 2025; an electricity sector specific carbon dioxide reduction of 35 percent below 2012 levels by 2030; and electricity savings through cost-effective energy efficiency of 2% of total electricity sales by 2020.

The Executive Order directs various state agencies to take steps to achieve these goals. It does not, by itself, create any binding obligations on industry, including utilities such as Tri-State. Nevertheless, the Executive Order expresses a policy goal and vision for the future that may result in regulatory actions by agencies such as the CPUC and the Colorado Department of Public Health and Environment. It is also possible that the Colorado General Assembly may also act to increase the percentage of renewable generation required under the RES.

While not tied directly to the Executive Order or the RES, the apparent shift toward state regulation of greenhouse gasses is illustrated by the PUC's 2017 decision on

Public Service Company of Colorado's 2016 Electric Resource Plan, which included the use of the "social cost of carbon." Decision No. C17-0316 at ¶¶ 82-89 (finding that "the [social cost of carbon] serves as a modeling tool to incorporate the social benefits of reducing [carbon] emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions.") (internal quotations omitted).

At the regional level, it is also foreseeable that a future RTO or Independent System Operator ("ISO") that includes Colorado may add carbon pricing to its market structures. For example, the New York ISO is currently examining the potential for using carbon pricing within its wholesale market, and it is foreseeable that other RTO/ISOs may consider doing the same. To the extent that Tri-State's Colorado transmission system is included in an ISO/RTO, consideration or implementation of a carbon price through such a market organization could become applicable to Tri-State.

## 4. Potential Benefits and Transmission Impacts to Colorado

In this scenario, generation is shifted from sources with higher carbon dioxide intensity (e.g., coal) to sources with lower carbon dioxide intensity (e.g., natural gas, wind, or solar). Such a shift could involve either reducing utilization or retirement of resources with higher carbon intensity, while increasing utilization of or constructing new resources with lower carbon intensity.

The existing Tri-State transmission system is built, in large part, to deliver power from large central-station generation facilities to Tri-State's Member Systems. The power generated by these plants as well as the location of each plant affects power flows on the Colorado transmission system and in the region, the reliability and quality of the power delivered throughout the state, and the capacity to add new generation resources to meet the state's energy needs. To the extent that carbon-reduction requirements shift generation away from such plants, the transmission system may need to be modified to ensure continued reliability and load-serving capacity.

For example, higher carbon intensity resources typically provide the baseload generation on the Tri-State system, whereas most renewable resources provide intermittent generation due to changing weather conditions. A shift away from baseload resources toward renewables, therefore, would also increase the demand for fast cycling gas combustion generators, which can be ramped up and down quickly to adjust for changing conditions in order to maintain system reliability. Under these circumstances, the increased renewable and gas-fired generation may not be located in the same place as the baseload generation being replaced, so new transmission may need to be constructed (or existing transmission expanded) to accommodate the increased reliance on the combination of renewables and gas.

Additionally, under the carbon reduction scenario, increased demand for renewable generation would likely increase the demand for suitable land near Tri-State load centers for siting such generation. To the extent that siting constraints are encountered, new renewable resources would need to be built farther from load centers resulting in new and longer transmission projects.

It is important to recognize that under this scenario, significant new or upgraded transmission elements will likely be required to accommodate the shift from high carbon intensity resources to lower carbon intensity resources for the reasons outlined here. The siting, permitting, and construction of transmission lines – especially larger and/or longer lines – is becoming increasingly challenging in Colorado. As a result, it may be difficult to timely place into service new or upgraded transmission lines needed to deliver power from new, lower-emitting resources. This is especially true in Colorado where large tracts of federal lands trigger lengthy federal permitting processes for new or modified transmission projects.

Notwithstanding these challenges, there are potential benefits to the Colorado transmission system under this scenario. For example, the development of new transmission lines needed to interconnect new lower-emitting resources could provide additional capacity and opportunities to interconnect additional resources in the future. New transmission infrastructure could also have the added benefit of relieving existing transmission system constraints and delaying or eliminating the need for improvements to or reconstruction of older transmission lines. Similarly, new transmission elements generally result in a more robust transmission system that may be better able to accommodate maintenance of transmission lines and ensure continued reliable power delivery during unscheduled transmission line outages. Finally, in conjunction with Scenario 3 below, which discusses increased operability between the Eastern and Western Interconnections, the greater need for transmission to integrate renewables could potentially create additional need for increased transmission ties between Colorado’s system and the Southwest Power Pool controlled system to the east.

**TSGT Scenario #2: Organized Markets**

## 1. Description

The MWTG, which includes Tri-State, is currently investigating the possibility of joining an organized electricity market such as the SPP. While that process has not yet reached a conclusion, it is reasonably foreseeable that the MWTG process could result in the MWTG utilities joining an organized market. This scenario considers the impacts and benefits to the Colorado transmission system that could result from membership in an organized market.

## 2. Rule 3627(e) Application

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | X |
| (III) | Emerging generation, transmission and demand limiting technologies | |
| (IV) | Various load growth projections | X |
| (V) | Scenarios Requested by Commission in 2016 biennial review process | |

## 3. Assumptions and Drivers

- Federal regulatory requirements such as FERC Order No. 1000 create incentives for regional approaches to transmission challenges such as those faced in Colorado.
- More than 60 percent of the electricity in the United States moves through regional wholesale markets, operated by RTOs or ISOs. The mountain west as a region has yet to adopt such markets, but recent developments continue to indicate the likelihood of mountain west utilities joining an organized market.
- Tri-State, along with Black Hills, Public Service, Basin Electric Power Cooperative, Colorado Springs Utilities, the Platte River Power Authority, and the Western Area Power Administration are all members of MWTG, which is currently investigating membership in SPP.
- In an RTO/ISO, the utilities would cede functional control of transmission to the RTO/ISO, which would plan and operate the systems of all member transmission owners.
- The MWTG participants have begun negotiations with SPP to explore membership in that RTO and are engaged in SPP's public stakeholder process. If successful and if necessary federal and state regulatory approvals are obtained, this could lead to

the MWTG utilities joining SPP with an organized market in the Rocky Mountain West by late-2019. In the event these discussions are unsuccessful, the MWTG utilities may pursue similar discussions with other RTOs and ISOs.

## 4. Potential Benefits and Transmission Impacts to Colorado

In an organized market, many decisions related to transmission planning, system operations, and resource dispatching are centralized to the RTO/ISO, rather than being carried out by each individual utility. This centralization would be the major impact to Colorado's transmission system in this scenario, as well as a significant potential benefit. While centralization of these services moves control over many transmission functions away from the utilities, the RTO/ISO can provide significant benefits in terms of efficient and reliable utilization of generation and transmission resources.

In general, an RTO/ISO would likely bring a wider perspective to grid management and transmission planning resulting in the potential for reduced costs, reduced congestion, and reduced risk of duplication on the transmission system. In an organized market, the RTO/ISO typically administers a regional transmission tariff, maintains a single OASIS, and determines available transfer capacity on the transmission system. The RTO/ISO also serves as the point of contact for many system interconnection requests. Each of these RTO/ISO functions has the potential to increase the efficient use of the transmission system. With the RTO/ISO overseeing day-to-day operation of the transmission system as well as transmission planning, the transmission system could potentially be planned as a whole on a regional level, rather than a set of interconnected parts owned by different utilities.

Correspondingly, however, centralization of these transmission functions would necessarily shift control away from the individual utilities such as Tri-State, and could potentially result in a risk of Colorado utilities participating in transmission projects that benefit the system as a whole, but that do not directly benefit Colorado customers.

**TSGT Scenario #3: Increased Role of Distributed Energy Resources**

## 1. Description

DER continue to play an increasing role in Colorado's energy mix. This scenario focuses on the growth of distributed energy technologies such as solar PV generation, advancements in energy storage, and increased interest in and deployment of other distributed resources such as community wind, geothermal, biomass, small and micro hydropower, coal mine methane, synthetic gas produced by pyrolysis of municipal solid waste, and recycled energy, as well as associated public policy developments. This scenario assumes continued and significant advancement and growth of such resources coupled with low load growth and higher efficiency, and considers the potential impact of such resources on the transmission system.

## 2. Rule 3627(e) Application

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | |
| (III) | Emerging generation, transmission and demand limiting technologies | X |
| (IV) | Various load growth projections | X |
| (V) | Scenarios Requested by Commission in 2016 biennial review process | |

## 3. Assumptions and Drivers

- The price of solar PV continues to fall.
- There is continued interest and increased penetration of community-based and behind the meter business models which make solar PV available to more consumers.
- Energy storage technologies, particularly batteries, continue to improve and prices continue to fall leading to wider deployment both in front of and behind the meter.
- Technological advances and regulatory policies are prompting utilities to explore the various applications of energy storage such as demand response, peak shaving, integration of renewables, and ancillary services.
- Existing and potentially increased state renewable energy standards and carbon reduction policies (see Scenario 1) will continue to drive the need for renewable resources at both the utility and consumer levels. These policy drivers are complemented by changing market forces that result in competitive prices for renewable resource generation.
- Siting and permitting of central station power plants, including large fossil-fueled generation resources, will become increasingly difficult.

## 4. Potential Benefits and Transmission Impacts to Colorado

An increase in DERs has the potential to delay or eliminate the need for new utility generation resources and significant transmission expansion, particularly if the DERs produce power during periods of peak demand. Distributed generation also has the potential to provide back-up power and reduce utility costs to the end user.

A potential consequence of high penetrations of distributed generation is that it can pose challenges to entities responsible for grid reliability. DERs are not always constructed at the location that is most beneficial to grid operations, and are not necessarily sized to meet system requirements. Furthermore, the wide range of DER types and sizes create uncertainties as to their operations and reliability. At high concentrations, DERs can impact the frequency and voltage performance of the local grid, especially following disturbances. The magnitude of their impact can be analyzed and incorporated into grid modeling, but only if the responsible entities participate in the analysis process.

**TSGT Scenario #4: Increased East-West Interconnection**

## 1. Description

This scenario focuses on increased coordination and transfer capabilities between the Eastern and Western Interconnections. This scenario is related to the Organized Market scenario discussed above and focuses specifically on the potential for new DC-Tie facilities, improvements to existing DC-Tie facilities, and the construction of new DC transmission lines.

## 2. Rule 3627(e) Application

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | |
| (III) | Emerging generation, transmission and demand limiting technologies | X |
| (IV) | Various load growth projections | X |
| (V) | Scenarios Requested by Commission in 2016 biennial review process | |

## 3. Assumptions and Drivers

- The MWTG utilities are currently exploring membership in SPP.
- One anticipated advantage of MWTG membership in SPP is the possibility of operating the transmission system and associated generating assets in the Eastern and Western Interconnections as a single, optimized market.
- Full realization of these benefits may require the construction of improved or new facilities linking the two interconnections. If the initial market operations are successful, this could create an incentive to increase the transfer capacity between the two interconnections.
- The cost of future DC-ties or DC-lines could be subject to the SPP planning and cost-allocation process.

## 4. Potential Benefits and Transmission Impacts to Colorado

Increased east-west interconnection would result in many of the same benefits and impacts discussed above with respect to participation in an organized market, although they are separate concepts. Better east-west interconnection could complement market participation, but is not necessary for such market participation to occur.  Instead, east-west interconnection would allow resources on Colorado's system to be used more readily on the SPP system, and vice-versa. Under this scenario, and assuming Colorado's utilities join SPP, resources could be dispatched across the entire SPP footprint as a single integrated system.

In general, this scenario could result in potential production savings costs from increased interconnection and the ability to schedule greater power flows between the eastern and western systems. Because the increased interconnection could provide more system flexibility, generation reserve requirements may be reduced and some new transmission projects may be avoided through regional solutions that also provide local transmission benefits.

It is possible that the costs of improvements to existing DC-Ties as well as the costs of constructing new DC-Ties or DC lines between the Eastern and Western Interconnections would be allocated among the SPP membership thereby potentially sparing Colorado utilities costs that would have been required if they sought to undertake such system improvements on their own.

# Appendix C

# Public Service Scenarios

**Public Service Scenario #1 Regional Market Dispatch**

## 1. *Description*

This scenario contemplates the development of a large-scale regional market that assumes a least-cost interconnection-wide dispatch with transmission solutions. This scenario has assumptions similar to the scenarios developed by WECC, which implicitly include an energy market across the interconnection that dispatches the least cost generation across the least cost transmission expansion needed to serve load but on a more regional basis. Public Service is currently involved in joint network tariff discussions with other Colorado utilities to determine if such a regional tariff can be developed and implemented.

## 2. *Rule 3627 (e) Application*

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | X |
| (III) | Emerging generation, transmission and demand limiting | X |
| (IV) | Various load growth projections | |
| (V) | Requested by Commission | |

## 3. *Potential Benefits and Transmission Impacts to Colorado*

Regional market operations, including the production-optimized cases used by WECC as a proxy, provide congestion price signals that indicate areas where transmission expansion could reduce societal costs for energy supply. The difficulty that still remains are the movement to a market based dispatch, regional tariff, and a means to address transmission investment and cost allocation.

**Public Service Scenario #2: Significant Load Growth Associated With Oil & Gas Exploration and Development**

## 1. *Description*

This scenario assumes that there are additional areas of load growth within the state that are specifically associated with oil and gas exploration and development -- for example, oil and gas development in northeast and western Colorado.

## 2. *Rule 3627 (e) Application*

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | X |
| (III) | Emerging generation, transmission and demand limiting | X |
| (IV) | Various load growth projections | X |
| (V) | Requested by Commission | |

## 3. *Potential Benefits and Transmission Impacts to Colorado*

If significant fossil fuel development occurred in areas of the state such as this, it could lead to additional transmission requirements, but possibly more local than regional. Public Service continues to be engages with CCPG groups such as the Northeast Colorado ("NECO") Subcommittee, which has been developing transmission plans for northeast Colorado, particularly in Weld County. In addition, Public Service has several planned and conceptual transmission projects for the Western Slope of Colorado that could be implemented depending on actual and forecasted load growth in the area.

**Public Service Scenario #3: High Penetration of Distributed Generation**

## 1. *Description*

This scenario addresses a situation that results in DG serving a significant portion of utility load, which could result in a reduced need for transmission expansion. Although this scenario could potentially slow the investment of new transmission development, transmission may be necessary to address other drivers and changes in energy delivery.

## 2. *Rule 3627 (e) Application*

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | **X** |
| (III) | Emerging generation, transmission and demand limiting | **X** |
| (IV) | Various load growth projections | **X** |
| (V) | Requested by Commission | |

## 3. *Potential Benefits and Transmission Impacts to Colorado*

Although this scenario could potentially slow the investment of new transmission development, transmission may be necessary to address other drivers and changes in energy delivery. A high penetration of DG could require changes in generation cost allocation; evaluations of new distribution reliability issues; increased flexible generation resources which could be different than the current resource mix that could result in the overbuild of capacity to ensure the appropriate resource flexibility; significant impact to reliability protection schemes on the distribution system; and the development of additional distribution reliability management systems that to date are not widely deployed. These management systems would be analogous to Supervisory Control and Data Acquisition ("SCADA") systems for the real-time operation and management of the transmission system. Extensive communication networks would be required as well as data handling.

# Appendix D

# CCPG Scenario

## CCPG Scenario: 20 Year Impact of State Statute RES Levels

### *1. Description*

This scenario contemplates that the requirements for utilities to serve demand with renewable energy will be modeled at 30% for PSCo and Black Hills, 20% for Tri-State, and 10% for all other utilities. Several sensitivities of this scenario were evaluated by the CCPG including a normal 2038 summer peak load and an off peak load scenario.

### *2. Rule 3627 (e)*

| Rule | Credible alternatives | Apply |
|---|---|---|
| (I) | Reasonably foreseeable future policy initiatives | X |
| (II) | Possible retirement of existing generation due to age, environmental regulations or economic considerations | X |
| (III) | Emerging generation, transmission and demand limiting | |
| (IV) | Various load growth projections | |
| (V) | Requested by Commission | X |

### *3. Assumptions and Drivers*

- 30% RES for Public Service and Black Hills, 20% for Tri-State, and 10% for other utilities
- 1.34% load growth
- Off-peak case with light loads and high wind outputs
- Renewable and conventional generation amounts and locations were contributed by the TPs and stakeholders.
- Transmission plans were added to a power flow analysis
- Detailed one-line diagrams were created from the power flow analysis for the summer peak case and the off-peak case

### *4. Indicators*

- Transmission plans include the Public Service Colorado Senate Bill 07-100 (“SB07-100”) facilities and additional transmission lines to accommodate the RES assumptions

- Transmission lines added from the resources to load center based on engineering judgment and empirical knowledge

### 5. ***Potential Impacts to Colorado***

If load continues to increase as modeled, significant transmission may need to be developed in the state to deliver renewable energy to load centers.

# COLORADO COORDINATED PLANNING GROUP
## CONCEPTUAL WORK GROUP

**<u>Year 2038 Conceptual Base Cases, Power Flow Models, and a Scenario Study</u>**

**January 4, 2018**

## Table of Contents

# I. EXECUTIVE SUMMARY

The Colorado Coordinated Planning Group (CCPG) created a Conceptual Planning Work Group (CPWG) to consider long term transmission planning issues into the future beyond the typical 10-year planning horizon normally evaluated by transmission planners and required by North American Electric Coordination Corporation (NERC) Planning Standards.

On May 27, 2010, the CPWG met for the first time and agreed to investigate three conceptual future scenarios. The initial analyses and study report were completed by the CPWG in 2011. The Scenario 1 future contemplated the need to increase the import/export transfer capability between Colorado, Wyoming, New Mexico, and Utah to enable lower cost energy to be delivered across those state boundaries. The CWPG agreed to look at what transmission might be required to allow a 1000 MW transfer capability. The Scenario 2 future contemplated retirement of all the coal fired power plants in the State of Colorado. The objective was to determine what transmission upgrades might be needed for such a scenario. The Scenario 3 future contemplated a public policy change in which higher renewable energy standards would be implemented. The CPWG agreed to create power flow models to represent various assumptions for Scenario 3, and perform at least one technical analysis to determine what transmission might be needed. The results were posted to the CPWG web page, and were also included in the 2012 Rule 3627 filing by Black Hills, Tri-State, and Public Service.

Subsequent to the first filing, consideration by the CPWG has focused solely on Scenario 3.

In early 2016, the CPWG agreed to create 2038 horizon year conceptual transmission models for both heavy and light summer. Public Service Company of Colorado, Black Hills Energy, Tri-State Generation and Transmission, Colorado Springs Utility, and Platte River Power Authority all submitted their loads and generation dispatch to build two year-2038 power flow models: 1) heavy summer model and 2) off-peak model. Upon the completion of this report, models may be used as appropriate for conceptual studies.

The 2038 horizon year aligns with the 20 year conceptual plan required by the Colorado Public Utilities Commission (CPUC) per Rule 3627.

This report describes a “what-if” scenario that represents year 2038 load, generation, and transmission network, for both heavy summer and off-peak loading conditions. The off-peak models 55% of the heavy summer peak load. The solar will be offline during the night when the wind energy output reaches its maximum capability and the load profile is about 55% of peak load during the day. The wind generation output needed to meet the RES for Colorado utilities were modeled at 80% of nameplate during the off-peak periods. The 80% output value for wind generation during off-peak period was chosen based on common industry practice. During these off-peak periods, the wind generation of 3265 MW is providing 49% of the demand load of 6619 MW. The Visio drawings depicting the power flows for the two models are shown on Figure 1 and Figure 2.

Using the 20-year CPWG model, a scenario study was done to examine the impact on the transmission system with the Comanche 3 coal unit retirement. Again, this is a very high level look of a “what-if” scenario and to comply with Colorado Bills and Rule 3627’s requirement of performing a study using the 20-year CPWG model. The results of this study indicated that the transmission system of Colorado may be adequate for the retirement of Comanche 3 by year 2038. In order to draw a definite conclusion, more studies such as transient stability and voltage stability will need to be done. Since Comanche 3 is the single largest unit in Colorado, losing that unit may pose quick event phenomena in the transient realm that do not show up in the steady state study. Voltage stability may also be a deciding factor due to the amount of reactive power that this unit generates for voltage regulation. All in all, this is a good scenario to contemplate because it will result in carbon dioxide emission reductions that the State of Colorado has set a goal to achieve and will help meet other proposed federal requirements.

# II. STUDY PROCESS

This 2038 report is an update to the 2036 year plan submitted to the CPUC on February 1, 2016. For the preparation of building the 2038 base cases, the utilities provided their forecasted year 2038 heavy summer peak load demand numbers and year 2015 historical load demand and energy consumption numbers as the starting point. The set of load demand numbers were used to calculate incremental increase in demand from 2015 to 2038 for each utility. The percentage of increase in the demand numbers was used to calculate the energy output needed to meet the RES requirement for each utility. Each of the utilities also provided their mix and type of renewable resources that existed by 2015 and those new renewable resources they have plans to add to their system from 2015 to 2038 to fulfill their energy requirements as presently required under Colorado Bills – Renewable Energy Standard (RES) 30% for Public Service and Black Hills, 20% for Tri-State[1] and 10% for all other utilities. In addition, each utility agreed to identify the Energy Resource Zone (ERZ) locations for their proposed renewable resources generation and their plant locations for their conventional generation to meet their load requirements. Tables 1-5 calculate each utility’s generation needs based on the loads plus 16% reserves; Tables 7-8 allocate the required generation to their proposed generation plant locations and ERZ’s. The generation plant locations and ERZ’s remain the same as the 2036 report.

# III. YEAR 2038 MODELS BUILDING

## A. Assumptions

The following assumptions were used to develop the 20-year conceptual model for the State of Colorado. These assumptions were recommended and agreed to by members of the CPWG.

### 1. Load Demand Forecasts and Energy Consumptions

Upon agreement by the CPWG, Black Hills Energy (BHE), Public Service Company of Colorado (PSCo), Colorado Springs Utilities (CSU), Platte River Power Authority (PRPA), and Tri-State Generation and Transmission (Tri-State), each provided a demand and energy “Base Case Forecast” for the year 2038; and an actual 2015 demand and energy load, see table 1-5. The composite of the individual utility 2038 year plans would

[1] Under HB10-1001 and SB13-252, investor-owned utilities are required to generate 30% of their electricity from renewable energy, of which 3% must come from distributed energy resources, cooperative utilities to generate 20% of their electricity from renewables by 2020, and 10% for others.

then be considered the 2038 plan for all the Colorado, see table 6. Also, Tables 1-5 calculated the generation output plus 16% generation reserve margin to meet the required Colorado renewable energy standard (RES) for the year 2038 with a 30% requirement for Black Hills and Public Service, 20% for Tri-State, and 10% for all other utilities. In addition, the tables also calculated the renewable generation demand available for the off-peak conditions, 55% of the heavy summer peak. Where no numbers were submitted by a utility, 20% of wind generation capacity was assumed during the peak and 80% wind generation capacity available for the off-peak.

### Heavy summer model

Traditional transmission planning is done using peak load conditions (typically heavy summer or heavy winter) where the maximum generation on the total system can be expected. These heavy peak periods then tend to define the transmission lines that need to be built to get the power to the load centers. A conceptual plan therefore was created to look at the heavy summer conditions for Colorado since electricity consumption peaks during the summer.

Base case forecast-summer peak

Using the existing actual 2015 demand and energy load and the 2038 demand and energy load forecasts from each individual utility (BHE, PSCo, CSU, PRPA, and Tri-State -see Tables 1-6) a generation plan was developed for each utility to determine the output of each generation type – conventional and renewable. The load forecast information from Table 1-6 shows that the composite load for these utilities was 9,985 MW for actual 2015 and 13,093 MW for 2038, the Base Case forecast. The load increases from 2015 to 2038 is 3,108 MW. Assuming a 16% reserve margin, the incremental generation needed to cover this load increase is 3605 MW. Attached Table 6 shows, on a utility by utility basis, the allocation of the renewable and conventional generation required to meet the Base Case 2038 summer peak as a composite for Colorado.

### Off-peak model

The off-peak is a time when the load demand on the electric system is significantly lower than the daily peak. The off-peak loads are typically the lowest during the night between 2:00-5:00 A.M. The minimum off-peak load occurs at night in the spring and in the fall when the weather is mild. For purposes of this report, the off-peak load was assumed to be 55% of the summer peak. Using the 2017 PSCo's load data on the day of the summer peak, PSCo's minimum peak load was 53% of their maximum summer peak load, so a 55% representation of the summer peak for Colorado appeared to be a reasonable representation for an off-peak period.

Base case forecast off-peak

Each utility provided information as to how much of their renewable generation would be on during the off-peak load period. Tables 1-5 show on a utility by utility basis the renewable and conventional generation that is available during the off-peak (55% of peak). The off-peak model assumed wind generation at 80% of capacity and solar generation to be at 0% of capacity. Attached Table 6 allocates on a utility by utility basis, the amount of conventional and renewable generation available to meet the 55%

load level. The total incremental wind level of off-peak generation for 2038 is calculated to be 1651 MW.

An off-peak case was created to present the magnitude of the challenges renewable generation presents to the transmission planning picture. The 2038 demand load at 55% of the peak is 6619 MW. This means that the wind generation is providing about 49% of the demand load with the remaining 51% of the load being supplied by conventional generation.

### 2. Allocation of Generation

a. For conventional generation, Table 7 shows the location and allocation of the assumed conventional generation in Colorado to make up for the load growth and 16% reserve margin.

b. For renewable generation, attached Tables 8, 8a, and 8b show the location and the allocation of the various renewable resources in the various ERZ's as reported by the utilities. These are the same tables used from previous filing.

## B. Analyses and Results

In comparing the loads of the proposed 2038 study year with the 2035 study year and 2036 study year, the 2035 and 2036 loads studied are comparable in magnitude to the 2038 study year – 14,040 MW for 2035, 13,334 MW for 2036 versus 13,093 MW for 2038. This is the total amount of load in the entire state of Colorado. Since it was assumed that each utility's percentage renewable energy requirement used in preparing the 2038 cases was the same as the 2035 and 2036 cases, this implies that the 2014 and 2016 studies still apply. The CPWG agreed that studies done for years 2035 and 2036 remain effective for the 2018 study year and do not need to be repeated. The 2035 and 2036 Conceptual Plan reports can be found on the CCPG Conceptual Planning Work Group page of the WestConnect website.

In comparing the incremental generation of the proposed 2038 study year with 2036 study year, the total amount of generation needed to meet the future 20 year demand is also comparable in magnitude – 3635 MW for 2036 versus 3265 for 2038. The total generation values for both the peak and off-peak cases have the 16% WECC reserve margin requirement built in.

Some of the note-worthy coal plant retirements expected by 2038 are:

1. Comanche Unit 1 and Unit 2, 360 MW each (modeled offline)
2. Craig Station Unit 1, 427 MW (deleted)
3. Nucla Station, 100 MW (deleted)

In comparing the transmission network of the proposed 2038 study year with 2036 study year, there are no significant changes between the 2036 study year and 2038 study year.

Links to past 20 year Conceptual Plan reports:

1. 2035 CPWG Report (filed in 2014 with Rule 3627)
2. 2036 CPWG Report (filed in 2016 with Rule 3627)

# IV. A SCENARIO STUDY - COMANCHE 3 COAL RETIREMENT

## A. Background

Comanche 3 Station near Pueblo, Colorado, erected in 2010, is a single largest unit in Colorado at 750 MW. The main source of fuel for Comanche 3 is supercritical pulverized coal. This unit is sitting next to Comanche 1 and 2, totaling up to 1,400 MW. Public Service is sole owner of Comanche 1 and 2, and the majority owner of Comanche 3 (500 MW). The other part owners are Intermountain Rural Electric and Holy Cross (250 MW).

## B. Study Objective

The intent of this scenario study was to look at the overall impact to the transmission system in the state of Colorado if Comanche 3 happens to be retired, focusing primary along the front range corridor where the power is being distributed.

## C. Methodology

This study included steady state power flow using the 2038 heavy summer model as a base case. Facility loadings and voltages were monitored within the study area consistent with NERC and WECC planning criteria. Using Siemens PSS/E software, single contingencies were performed on the benchmark case and with Comanche 3 out. The generation loss at Comanche 3 was made up at various places in the system, including gas, wind, and solar – see Table 9 for generation dispatch. The results of the steady state analysis were tabulated in Table 10.

## D. Analysis and Results

In comparing the pre and post Comanche 3 retirement, the single contingency study results shown in Table 10 indicated no new thermal and voltage violations. Based on this analysis alone, the system exhibited acceptable contingency performance, and no transmission upgrades were needed for the retirement of Comanche 3 unit. Since this was a very cursory assessment of the Comanche 3 retirement, other studies such as transient stability and voltage stability would be needed to verify the conclusion. The power flow PSS/E case with Comanche 3 out is also available for CCPG members to use.

# V. CONCLUSIONS

This long term case building exercise is to provide a look at a scenario as described above. CCPG members can utilize these models as a starting point for other future scenarios to evaluate what transmission upgrades might be required for those conditions.

Based on the results from the preliminary power flow study using the 2038 heavy summer model, the transmission system in Colorado appeared to be adequate for the retirement of Comanche 3 coal unit. Additional analyses would need to be performed in order to draw a certain conclusion.

## VI. DESCRIPTION OF THE TABLES, FIGURES, AND APPENDICES

**Tables 1-6:** These tables show on a utility by utility basis the generation types (renewable and conventional) needed to meet the state energy renewable requirements by 2038.

**Table 7**: This table shows the allocation and location of the conventional generation for all the utilities needed by 2038.

**Tables 8:** This table shows information as provided by the utilities on a utility by utility basis on the ERZ location.

**Tables 9:** This table shows the dispatch for Comanche 3 coal retirement study.

**Tables 10:** This table shows the thermal and voltage results for the Comanche 3 coal retirement study.

**Figure 1:** Visio diagram depicts the actual power flow of the 2038 heavy summer base case.

**Figure 2:** Visio diagram depicts the actual power flow of the 2038 off-peak base case.

**Black Hills Colorado 2038**

## I. HISTORICAL TEST YEAR - 2015: DEMAND, ENERGY, PERCENT RPS, AND RENEWABLE RESOURCES

FILL IN SHADED CELLS WITH DATA

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Renewable Resource Capacity Factor | Renewable Resource Nameplate Capacity MW | Renewable Resource Energy Output - MWh |
|---|---|---|---|---|---|---|---|
| Present Year Demand, Energy, and RPS | 394 | 1993371 | 30% | 598011 | | | |
| Wind | | | | | 0.36 | 146.4 | 461687 |
| Solar | | | | | 0.00 | 0 | 0 |
| Photo voltaic | | | | | 0.00 | 0 | 0 |
| With Storage | | | | | 0.00 | 0 | 0 |
| Hydro | | | | | 0.00 | 0 | 0 |
| Bio-mass | | | | | 0.00 | 0 | 0 |
| Total present year renewable capacity | | | | | | 146.4 | |
| Total present year renewable energy | | | | | | | 461687 |

## II. GENERATION TO BE ADDED BETWEEN THE PRESENT YEAR AND YEAR TWENTY

| | Capacity Factor | Nameplate Capacity MW | Energy Output - MWh |
|---|---|---|---|
| Wind | 0.00 | 0 | 0 |
| Solar | 0.00 | 0 | 0 |
| Photo voltaic | 0.00 | 0 | 0 |
| With Storage | 0.00 | 0 | 0 |
| Hydro | 0.00 | 0 | 0 |
| Bio-mass | 0.00 | 0 | 0 |
| Other | 0.00 | 0 | 0 |
| Total Added Renewable Capacity | | 0.0 | |
| Total Added Renewable Energy | | | 0 |
| Total Renewable Energy up to Year Twenty | | | 461687 |

## III. YEAR TWENTY - 2038: FORECASTED DEMAND, ENERGY, AND PERCENT RPS

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Total Existing RPS Energy up-to Year Twenty - MWh | Additional RPS Energy Needed at Year Twenty | Additional Capacity Needed at Year Twenty |
|---|---|---|---|---|---|---|---|
| Growth 1.10% per year | 442 | 2190000 | 30% | 657000 | 461687 | 195313 | 48 |

## IV. RENEWABLE (ENERGY) GENERATION RATIO'D TO MEET THE RPS REQUIREMENT AT YEAR TWENTY

| | Renewable Resource Energy Output - MWh | Renewable Resource Capacity Factor | Resultant Nameplate Capacity MW |
|---|---|---|---|
| Wind | 195313 | 0.36 | 62 |
| Solar | 0 | 0.00 | 0 |
| Photo voltaic | 0 | 0.00 | 0.0 |
| With Storage | 0 | 0.00 | 0.0 |
| Hydro | 0 | 0.00 | 0.0 |
| Bio-mass | 0 | 0.00 | 0.0 |
| Other | 0 | 0.00 | 0.0 |
| Total Renewable Energy from Generation added in Year Twenty: | 195313 | | |

## V. ON-PEAK CALCULATIONS AT YEAR TWENTY

| | Total Nameplate Capacity MW | On-Peak Capacity Credit | Resultant Capacity MW | Planning Reserve Requirement |
|---|---|---|---|---|
| Wind | 62 | 0.36 | 22 | 0.16 |
| Solar | 0 | 0.00 | 0 | |
| Photo voltaic | 0 | 0.00 | 0 | |
| With Storage | 0 | 0.00 | 0 | |
| Hydro | 0 | 0.00 | 0 | |
| Bio-mass | 0 | 0.00 | 0 | |
| Other | 0 | 0.00 | 0 | |
| Incremental Conventional/Other Generation | 33 | 1.00 | 33 | |
| Net On-Peak Generation added at Year Twenty | | | 56 | |

## VI. OFF-PEAK CALCULATIONS AT YEAR TWENTY

Off-Peak Multiplier of Peak Demand: 0.55 Off-Peak MW: 243.1

| | Total Nameplate Capacity MW | Off-Peak Capacity Credit | Resultant Capacity MW |
|---|---|---|---|
| Wind | 61.9 | 0.80 | 50 |
| Solar | 0.0 | 0.00 | 0 |
| Photo voltaic | 0.0 | 0.00 | 0 |
| With Storage | 0.0 | 0.00 | 0 |
| Hydro | 0.0 | 0.00 | 0 |
| Bio-mass | 0.0 | 0.00 | 0 |
| Other | 0.0 | 0.00 | 0 |
| Incremental Conventional/Other Generation | 33 | 1.00 | 33 |
| Net Off-Peak Generation Available at Year Twenty | | | 83 |

**Public Service Company of Colorado 2038**

## I. HISTORICAL TEST YEAR - 2015: DEMAND, ENERGY, PERCENT RPS, AND RENEWABLE RESOURCES

FILL IN SHADED CELLS WITH DATA

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Renewable Resource Capacity Factor | Renewable Resource Nameplate Capacity MW | Renewable Resource Energy Output - MWh |
|---|---|---|---|---|---|---|---|
| Present Year Demand, Energy, and RPS | 6388 | 34221369 | 30% | 10266411 | | | |
| Wind | | | | | 0.37 | 3216.0 | 10423699 |
| Solar | | | | | 0.28 | 246 | 603389 |
| Photo voltaic | | | | | 0.00 | 0 | 0 |
| With Storage | | | | | 0.00 | 0 | 0 |
| Hydro | | | | | 0.00 | 0 | 0 |
| Bio-mass | | | | | 0.00 | 0 | 0 |
| Total present year renewable capacity | | | | | | 3462.0 | |
| Total present year renewable energy | | | | | | | 11027088 |

## II. GENERATION TO BE ADDED BETWEEN THE PRESENT YEAR AND YEAR TWENTY

| | Capacity Factor | Nameplate Capacity MW | Energy Output - MWh |
|---|---|---|---|
| Wind | 0.37 | 700 | 2268840 |
| Solar | 0.28 | 400 | 981120 |
| Photo voltaic | 0.00 | 0 | 0 |
| With Storage | 0.00 | 0 | 0 |
| Hydro | 0.00 | 0 | 0 |
| Bio-mass | 0.00 | 0 | 0 |
| Other | 0.00 | 0 | 0 |
| Total Added Renewable Capacity | | 1100.0 | |
| Total Added Renewable Energy | | | 3249960 |
| Total Renewable Energy up to Year Twenty | | | 14277048 |

## III. YEAR TWENTY - 2038: FORECASTED DEMAND, ENERGY, AND PERCENT RPS

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Total Existing RPS Energy up-to Year Twenty - MWh | Additional RPS Energy Needed at Year Twenty | Additional Capacity Needed at Year Twenty |
|---|---|---|---|---|---|---|---|
| Growth 1.10% per year | 7998 | 42846354 | 30% | 12853906 | 14277048 | -1423142 | 1610 |

## IV. RENEWABLE (ENERGY) GENERATION RATIO'D TO MEET THE RPS REQUIREMENT AT YEAR TWENTY

| | Renewable Resource Energy Output - MWh | Renewable Resource Capacity Factor | Resultant Nameplate Capacity MW |
|---|---|---|---|
| Wind | -1265197 | 0.37 | -390 |
| Solar | -157944 | 0.28 | -64 |
| Photo voltaic | 0 | 0.00 | 0.0 |
| With Storage | 0 | 0.00 | 0.0 |
| Hydro | 0 | 0.00 | 0.0 |
| Bio-mass | 0 | 0.00 | 0.0 |
| Other | 0 | 0.00 | 0.0 |
| Total Renewable Energy from Generation added in Year Twenty: | -1423142 | | |

## V. ON-PEAK CALCULATIONS AT YEAR TWENTY

| | Total Nameplate Capacity MW | On-Peak Capacity Credit | Resultant Capacity MW | Planning Reserve Requirement |
|---|---|---|---|---|
| Wind | 700 | 0.37 | 259 | 0.16 |
| Solar | 400 | 0.28 | 112 | |
| Photo voltaic | 0.0 | 0.00 | 0 | |
| With Storage | 0.0 | 0.00 | 0 | |
| Hydro | 0.0 | 0.00 | 0 | |
| Bio-mass | 0.0 | 0.00 | 0 | |
| Other | 0.0 | 0.00 | 0 | |
| Incremental Conventional/Other Generation | 1497 | 1.00 | 1497 | |
| Net On-Peak Generation added at Year Twenty | | | 1868 | |

## VI. OFF-PEAK CALCULATIONS AT YEAR TWENTY

Off-Peak Multiplier of Peak Demand: 0.55 Off-Peak MW: 4398.9

| | Total Nameplate Capacity MW | Off-Peak Capacity Credit | Resultant Capacity MW |
|---|---|---|---|
| Wind | 309.7 | 0.80 | 248 |
| Solar | 335.6 | 0.00 | 0 |
| Photo voltaic | 0.0 | 0.00 | 0 |
| With Storage | 0.0 | 0.00 | 0 |
| Hydro | 0.0 | 0.00 | 0 |
| Bio-mass | 0.0 | 0.00 | 0 |
| Other | 0.0 | 0.00 | 0 |
| Incremental Conventional/Other Generation | 1497 | 1.00 | 1497 |
| Net Off-Peak Generation Available at Year Twenty | | | 1744 |

**Colorado Springs Utilities 2038**

FILL IN SHADED CELLS WITH DATA

## I. HISTORICAL TEST YEAR - 2015: DEMAND, ENERGY, PERCENT RPS, AND RENEWABLE RESOURCES

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Renewable Resource Capacity Factor | Renewable Resource Nameplate Capacity MW | Renewable Resource Energy Output - MWh |
|---|---|---|---|---|---|---|---|
| Present Year Demand, Energy, and RPS | 851 | 4699000 | 10% | 469900 | | | |
| Wind | | | | | 0.00 | 0 | 0 |
| Solar | | | | | 0.00 | 0 | 0 |
| Photo voltaic | | | | | 0.00 | 0 | 0 |
| With Storage | | | | | 0.00 | 0 | 0 |
| Hydro | | | | | 0.00 | 0 | 0 |
| Bio-mass | | | | | 0.00 | 0 | 0 |
| Total present year renewable capacity | | | | | | 0.0 | |
| Total present year renewable energy | | | | | | | 0 |

## II. GENERATION TO BE ADDED BETWEEN THE PRESENT YEAR AND YEAR TWENTY

| | Capacity Factor | Nameplate Capacity MW | Energy Output - MWh |
|---|---|---|---|
| Wind | 0.00 | 0 | 0 |
| Solar | 0.25 | 130 | 284700 |
| Photo voltaic | 0.00 | 0 | 0 |
| With Storage | 0.00 | 0 | 0 |
| Hydro | 0.29 | 35 | 89730 |
| Bio-mass | 0.00 | 0 | 0 |
| Other | 1.00 | 11 | 96360 |
| Total Added Renewable Capacity | | 176.2 | |
| Total Added Renewable Energy | | | 470790 |
| Total Renewable Energy up to Year Twenty | | | 470790 |

## III. YEAR TWENTY - 2038: FORECASTED DEMAND, ENERGY, AND PERCENT RPS

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Total Existing RPS Energy up-to Year Twenty - MWh | Additional RPS Energy Needed at Year Twenty | Additional Capacity Needed at Year Twenty |
|---|---|---|---|---|---|---|---|
| Growth 1.10% per year | 1142 | 5984000 | 10% | 598400 | 470790 | 127610 | 291 |

## IV. RENEWABLE (ENERGY) GENERATION RATIO'D TO MEET THE RPS REQUIREMENT AT YEAR TWENTY

| | Renewable Resource Energy Output - MWh | Renewable Resource Capacity Factor | Resultant Nameplate Capacity MW |
|---|---|---|---|
| Wind | 0 | 0.00 | 0 |
| Solar | 77169 | 0.25 | 35 |
| Photo voltaic | 0 | 0.00 | 0.0 |
| With Storage | 0 | 0.00 | 0.0 |
| Hydro | 24322 | 0.29 | 9.6 |
| Bio-mass | 0 | 0.00 | 0.0 |
| Other | 26119 | 1.00 | 3.0 |
| Total Renewable Energy from Generation added in Year Twenty: | 127610 | | |

## V. ON-PEAK CALCULATIONS AT YEAR TWENTY

| | Total Nameplate Capacity MW | On-Peak Capacity Credit | Resultant Capacity MW | Planning Reserve Requirement |
|---|---|---|---|---|
| Wind | 0 | 0.00 | 0 | 0.16 |
| Solar | 130 | 0.25 | 32 | |
| Photo voltaic | 0.0 | 0.00 | 0 | |
| With Storage | 0.0 | 0.00 | 0 | |
| Hydro | 44.8 | 0.29 | 13 | |
| Bio-mass | 0.0 | 0.00 | 0 | |
| Other | 14.0 | 1.00 | 14 | |
| Incremental Conventional/Other Generation | 292 | 1.00 | 292 | |
| Net On-Peak Generation added at Year Twenty | | | 352 | |

## VI. OFF-PEAK CALCULATIONS AT YEAR TWENTY

Off-Peak Multiplier of Peak Demand: 0.55 Off-Peak MW: 628.1

| | Total Nameplate Capacity MW | Off-Peak Capacity Credit | Resultant Capacity MW |
|---|---|---|---|
| Wind | 0.0 | 0.80 | 0 |
| Solar | 165.2 | 0.00 | 0 |
| Photo voltaic | 0.0 | 0.00 | 0 |
| With Storage | 0.0 | 0.00 | 0 |
| Hydro | 44.8 | 0.00 | 0 |
| Bio-mass | 0.0 | 0.00 | 0 |
| Other | 14.0 | 0.00 | 0 |
| Incremental Conventional/Other Generation | 292 | 1.00 | 292 |
| Net Off-Peak Generation Available at Year Twenty | | | 292 |

**Platte River Power Authority 2038**

FILL IN SHADED CELLS WITH DATA

## I. HISTORICAL TEST YEAR - 2015: DEMAND, ENERGY, PERCENT RPS, AND RENEWABLE RESOURCES

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Renewable Resource Capacity Factor | Renewable Resource Nameplate Capacity MW | Renewable Resource Energy Output - MWh |
|---|---|---|---|---|---|---|---|
| Present Year Demand, Energy, and RPS | 649 | 3195585 | 10% | 319559 | | | |
| Wind | | | | | 0.00 | 0 | 0 |
| Solar | | | | | 0.25 | 30 | 65700 |
| Photo voltaic | | | | | 0.00 | 0 | 0 |
| With Storage | | | | | 0.00 | 0 | 0 |
| Hydro | | | | | 0.00 | 0 | 0 |
| Bio-mass | | | | | 0.00 | 0 | 0 |
| Total present year renewable capacity | | | | | | 30.0 | |
| Total present year renewable energy | | | | | | | 65700 |

## II. GENERATION TO BE ADDED BETWEEN THE PRESENT YEAR AND YEAR TWENTY

| | Capacity Factor | Nameplate Capacity MW | Energy Output - MWh |
|---|---|---|---|
| Wind | 0.00 | 0 | 0 |
| Solar | 0.00 | 0 | 0 |
| Photo voltaic | 0.00 | 0 | 0 |
| With Storage | 0.00 | 0 | 0 |
| Hydro | 0.00 | 0 | 0 |
| Bio-mass | 0.00 | 0 | 0 |
| Other | 0.00 | 0 | 0 |
| Total Added Renewable Capacity | | 0.0 | |
| Total Added Renewable Energy | | | 0 |
| Total Renewable Energy up to Year Twenty | | | 65700 |

## III. YEAR TWENTY - 2038: FORECASTED DEMAND, ENERGY, AND PERCENT RPS

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Total Existing RPS Energy up-to Year Twenty - MWh | Additional RPS Energy Needed at Year Twenty | Additional Capacity Needed at Year Twenty |
|---|---|---|---|---|---|---|---|
| Growth 1.10% per year | 853 | 4166240 | 10% | 416624 | 65700 | 350924 | 204 |

## IV. RENEWABLE (ENERGY) GENERATION RATIO'D TO MEET THE RPS REQUIREMENT AT YEAR TWENTY

| | Renewable Resource Energy Output - MWh | Renewable Resource Capacity Factor | Resultant Nameplate Capacity MW |
|---|---|---|---|
| Wind | 0 | 0.00 | 0 |
| Solar | 350924 | 0.25 | 160 |
| Photo voltaic | 0 | 0.00 | 0.0 |
| With Storage | 0 | 0.00 | 0.0 |
| Hydro | 0 | 0.00 | 0.0 |
| Bio-mass | 0 | 0.00 | 0.0 |
| Other | 0 | 0.00 | 0.0 |
| Total Renewable Energy from Generation added in Year Twenty: | 350924 | | |

## V. ON-PEAK CALCULATIONS AT YEAR TWENTY

| | Total Nameplate Capacity MW | On-Peak Capacity Credit | Resultant Capacity MW | Planning Reserve Requirement |
|---|---|---|---|---|
| Wind | 0 | 0.00 | 0 | 0.16 |
| Solar | 0 | 0.25 | 0 | |
| Photo voltaic | 0.0 | 0.00 | 0 | |
| With Storage | 0.0 | 0.00 | 0 | |
| Hydro | 0.0 | 0.29 | 0 | |
| Bio-mass | 0.0 | 0.00 | 0 | |
| Other | 0.0 | 1.00 | 0 | |
| Incremental Conventional/Other Generation | 237 | 1.00 | 237 | |
| Net On-Peak Generation added at Year Twenty | | | 237 | |

## VI. OFF-PEAK CALCULATIONS AT YEAR TWENTY

Off-Peak Multiplier of Peak Demand: 0.55 Off-Peak MW: 469.15

| | Total Nameplate Capacity MW | Off-Peak Capacity Credit | Resultant Capacity MW |
|---|---|---|---|
| Wind | 0.0 | 0.80 | 0 |
| Solar | 160.2 | 0.00 | 0 |
| Photo voltaic | 0.0 | 0.00 | 0 |
| With Storage | 0.0 | 0.00 | 0 |
| Hydro | 0.0 | 0.00 | 0 |
| Bio-mass | 0.0 | 0.00 | 0 |
| Other | 0.0 | 0.00 | 0 |
| Incremental Conventional/Other Generation | 237 | 1.00 | 237 |
| Net Off-Peak Generation Available at Year Twenty | | | 237 |

**Tri-State G&T 2038**

FILL IN SHADED CELLS WITH DATA

## I. HISTORICAL TEST YEAR - 2015: DEMAND, ENERGY, PERCENT RPS, AND RENEWABLE RESOURCES

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Renewable Resource Capacity Factor | Renewable Resource Nameplate Capacity MW | Renewable Resource Energy Output - MWh |
|---|---|---|---|---|---|---|---|
| Present Year Demand, Energy, and RPS | 1706 | 9928000 | 10% | 992800 | | | |
| Wind | | | | | 0.00 | 0 | 0 |
| Solar | | | | | 0.00 | 0 | 0 |
| Photo voltaic | | | | | 0.00 | 0 | 0 |
| With Storage | | | | | 0.00 | 0 | 0 |
| Hydro | | | | | 0.00 | 0 | 0 |
| Bio-mass | | | | | 0.00 | 0 | 0 |
| Total present year renewable capacity | | | | | | 0.0 | |
| Total present year renewable energy | | | | | | | 0 |

## II. GENERATION TO BE ADDED BETWEEN THE PRESENT YEAR AND YEAR TWENTY

| | Capacity Factor | Nameplate Capacity MW | Energy Output - MWh |
|---|---|---|---|
| Wind | 0.40 | 369 | 1292976 |
| Solar | 0.40 | 29 | 101616 |
| Photo voltaic | 0.00 | 0 | 0 |
| With Storage | 0.00 | 0 | 0 |
| Hydro | 0.50 | 7 | 30660 |
| Bio-mass | 0.40 | 13 | 45552 |
| Other | 0.00 | 0 | 0 |
| Total Added Renewable Capacity | | 418.0 | |
| Total Added Renewable Energy | | | 1470804 |
| Total Renewable Energy up to Year Twenty | | | 1470804 |

## III. YEAR TWENTY - 2038: FORECASTED DEMAND, ENERGY, AND PERCENT RPS

| | Demand MW | Energy MWh | RPS | RPS Energy MWh | Total Existing RPS Energy up-to Year Twenty - MWh | Additional RPS Energy Needed at Year Twenty | Additional Capacity Needed at Year Twenty |
|---|---|---|---|---|---|---|---|
| Growth 1.10% per year | 2658 | 14692254 | 10% | 1469225 | 1470804 | -1579 | 952 |

## IV. RENEWABLE (ENERGY) GENERATION RATIO'D TO MEET THE RPS REQUIREMENT AT YEAR TWENTY

| | Renewable Resource Energy Output - MWh | Renewable Resource Capacity Factor | Resultant Nameplate Capacity MW |
|---|---|---|---|
| Wind | -1388 | 0.40 | 0.0 |
| Solar | -109 | 0.40 | 0.0 |
| Photo voltaic | 0 | 0.00 | 0.0 |
| With Storage | 0 | 0.00 | 0.0 |
| Hydro | -33 | 0.50 | 0.0 |
| Bio-mass | -49 | 0.40 | 0.0 |
| Other | 0 | 0.00 | 0.0 |
| Total Renewable Energy from Generation added in Year Twenty: | -1579 | | |

## V. ON-PEAK CALCULATIONS AT YEAR TWENTY

| | Total Nameplate Capacity MW | On-Peak Capacity Credit | Resultant Capacity MW | Planning Reserve Requirement |
|---|---|---|---|---|
| Wind | 369 | 0.40 | 148 | 0.16 |
| Solar | 29 | 0.40 | 12 | |
| Photo voltaic | 0.0 | 0.00 | 0 | |
| With Storage | 0.0 | 0.00 | 0 | |
| Hydro | 7.0 | 0.50 | 3 | |
| Bio-mass | 13.0 | 0.40 | 5 | |
| Other | 0.0 | 0.00 | 0 | |
| Incremental Conventional/Other Generation | 936 | 1.00 | 936 | |
| Net On-Peak Generation added at Year Twenty | | | 1104 | |

## VI. OFF-PEAK CALCULATIONS AT YEAR TWENTY

Off-Peak Multiplier of Peak Demand: 0.55 Off-Peak MW: 1461.9

| | Total Nameplate Capacity MW | Off-Peak Capacity Credit | Resultant Capacity MW |
|---|---|---|---|
| Wind | 369.0 | 0.80 | 295 |
| Solar | 29.0 | 0.00 | 0 |
| Photo voltaic | 0.0 | 0.00 | 0 |
| With Storage | 0.0 | 0.00 | 0 |
| Hydro | 7.0 | 0.00 | 0 |
| Bio-mass | 13.0 | 0.00 | 0 |
| Other | 0.0 | 0.00 | 0 |
| Incremental Conventional/Other Generation | 936 | 1.00 | 936 |
| Net Off-Peak Generation Available at Year Twenty | | | 1232 |

## 2038 Base Forecast for Colorado

**Heavy Summer Peak**
**Incremental Generation -MW**
**from 2015 to 2038**

| Utility | 2038 Load- MW | Incremental 2015-2038 Load-MW | Gen Solar Gs(PV) | Gen Solar Gs(CS) | Gen Wind Gw | Gen Hydro Gh | Gen Bio-mass Gb | Gen Other Go | Gen Conventional Gc | Gen Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Hills Colorado | 442 | 48 | 0 | 0 | 62 | 0 | 0 | 0 | 33 | 95 |
| Public Service | 7998 | 1610 | 0 | 0 | 0 | 0 | 0 | 0 | 1497 | 1497 |
| Colorado Springs Utilities | 1142 | 291 | 0 | 35 | 0 | 10 | 0 | 3 | 292 | 340 |
| PRPA | 853 | 204 | 0 | 160 | 0 | 0 | 0 | | 237 | 397 |
| Tri-State G&T | 2658 | 952 | 0 | 0 | 0 | 0 | 0 | 0 | 936 | 936 |
| Totals | 13093 | 3105 | 0 | 195 | 62 | 10 | 0 | 3 | 2995 | 3265 |

| 55% Off-Peak | 2038 Load- MW | Incremental 2015-2038 Load-MW | Gen Solar Gs(PV) | Gen Solar Gs(CS) | Gen Wind Gw | Gen Hydro Gh | Gen Bio-mass Gb | Gen Other Go | Gen Conventional Gc | Gen Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Hills Colorado | 243 | 26 | 0 | 0 | 28 | 0 | 0 | 0 | 25 | 53 |
| Public Service | 4399 | 886 | 0 | 0 | 0 | 0 | 0 | 0 | 823 | 823 |
| Colorado Springs Utilities | 628 | 160 | 0 | 0 | 0 | 10 | 0 | 3 | 161 | 173 |
| PRPA | 469 | 112 | 0 | 0 | 0 | 0 | 0 | | 130 | 130 |
| Tri-State G&T | 1462 | 524 | 0 | 0 | 0 | 0 | 0 | 0 | 515 | 515 |
| Totals | 7201 | 1708 | 0 | 0 | 28 | 10 | 0 | 3 | 1654 | 1695 |

Table 6

## Allocation of Conventional Generation - Year 2038

| | Base MW |
|---|---|
| **PSCo** | |
| Pawnee-20% | 300 |
| Ft. St. Vrain-20% | 300 |
| RMEC-20% | 300 |
| Spruce-20% | 300 |
| Cherokee-20% | 300 |
| Total | 1500 |
| **Black Hills** | |
| Airport Tap-100% | 33 |
| **Colo Spgs Utilities** | |
| Nixon-100% | 292 |
| **Platte River** | |
| Rawhide-100% | 237 |
| **Tri-State** | |
| Lamar-100% | 936 |
| **Total** | 2998 |

**Table 7**

## Year 2038 - Name plate Demand

**Provided by utilities**

| Wind Generation | | ERZ1 | | ERZ2 | ERZ3 | ERZ4 | ERZ5 | ERZ0** | Req'd MW | (+ or -) |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Hills | | | | | | | 170 | | 170 | 0 |
| PSCo | | 75 | | 450 | 1159 | | | 0 | 1684 | 0 |
| CSU | | | | | | | 50 | | 43 | 7 |
| PRPA | | 70 | | | | | | | 70 | 0 |
| Tri-State | | 142 | | 150 | 414 | | | | 679 | 27 |
| | Total | 287 | 0 | 600 | 1573 | 0 | 220 | 0 | 2646 | 34 |

| Solar Generation | | ERZ1 | | ERZ2 | ERZ3 | ERZ4 | ERZ5 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Black Hills | | | | | | | 38 | | 38 | 0 |
| PSCo | | | | | | 162 | 120 | | 282 | 0 |
| CSU | | | | | | | 75 | | 68 | 7 |
| PRPA | | | | | | | | 54 | 54 | 0 |
| Tri-State | | | | | 1 | | | | 1 | 0 |
| | Total | 0 | | | 1 | 162 | 233 | 54 | 443 | 7 |

**Denver area/Other

**Table 8**

Table 9. Comanche 3 Coal Retirement Dispatch

| **Comanche 3 Retirement Dispatch** | | | |
|---|---|---|---|
| | | | |
| | Location | Type | MW |
| Minus | Comanche 3 | Coal | -666 |
| | | | |
| Add | Comanche Solar | Solar | 300 |
| | Ft. St. Vrain | Gas | 200 |
| | Missile Site | Wind | 200 |

. PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS(R)E WED, DEC 13 2017 14:14 PAGE 30 .
.
.
. AC CONTINGENCY REPORT FOR 2 AC CONTINGENCY CALCULATION RUNS .
.
.
. BASE CASE MONITORED BRANCHES LOADED ABOVE 100.0% OF RATING SET A - ALL VIOLATIONS .
. % LOADING VALUES ARE % MVA FOR TRANSFORMERS AND % CURRENT FOR NON-TRANSFORMER BRANCHES .
...............................................................................................................

| X--- MONITORED ELEMENT ----X | 2038HS_preCom3OUT.acc | 2038HS_Com3OUT.acc |
|---|---|---|
| 70231 HOPKINS 115.00<br>70267 HOPKINS 69.000 T1 | 103.1%<br>38MVA | 102.9%<br>38MVA |
| 70630 RUSHCK2 345.00<br>70631 RUSHCK_W2 34.500 T1 | | 118.0%<br>567MVA |
| 71006 RTLSNAKEB 115.00<br>71008 BUSCHRNCH1 34.500 T1 | 162.8%<br>65MVA | 160.5%<br>64MVA |
| 71007 BUSCHRNCH2 34.500<br>71008 BUSCHRNCH1 34.500 1 | 193.1%<br>31MVA | 191.9%<br>30MVA |

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. AC CONTINGENCY REPORT FOR 2 AC CONTINGENCY CALCULATION RUNS .
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. CONTINGENCY CASE MONITORED BRANCHES LOADED ABOVE 100.0% OF RATING SET A - WORST CASE VIOLATIONS .
. % LOADING VALUES ARE % MVA FOR TRANSFORMERS AND % CURRENT FOR NON-TRANSFORMER BRANCHES .
. THRESHOLD FOR THE COUNT OF CONTINGENCIES CAUSING OVERLOADING IS 100.0% OF RATING SET A .
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| X--- MONITORED ELEMENT ----X | X-----LABEL----X | 2038HS_preCom3OUT.acc | 2038HS_Com3OUT.acc |
|---|---|---|---|
| 70023 ALLISON 115.00<br>70400 SODALAKE 115.00 1 | SINGL1 70045-70242(1) | 105.9%<br>163MVA<br>(2x) | 106.2%<br>163MVA<br>(2x) |
| 70025 ALMSA_TM 115.00<br>70026 ALMSA_TM 69.000 T1 | SINGL1 70228-70361(1) | 122.3%<br>31MVA<br>(6x) | 122.2%<br>31MVA<br>(6x) |
| 70037 ARAP_B 115.00 | SINGL1 70045-702 | | 100.6% |

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 70401 SOUTH_1     115.00 1  | 08(1)             |          |   158MVA |
                             |                   |          |     (1x) |
-----------------------------|-------------------|----------|----------|
 70045 BANCROFT    115.00    | SINGL1 70023-704  |   104.9% |   105.2% |
 70242 KENDRICK    115.00 1  | 00(1)             |   163MVA |   163MVA |
                             |                   |     (1x) |     (1x) |
-----------------------------|-------------------|----------|----------|
 70059 BO_TERM     115.00    | SINGL1 70059-704  |   112.8% |   114.6% |
 70444 VALMONT     115.00 2  | 44(1)             |   139MVA |   141MVA |
                             |                   |     (1x) |     (1x) |
-----------------------------|-------------------|----------|----------|
 70073 CALIFOR     115.00    | SINGL1 70108-702  |   114.2% |   116.1% |
 70108 CHEROKEE_S  115.00 1  | 76(1)             |   161MVA |   163MVA |
                             |                   |     (3x) |     (3x) |
-----------------------------|-------------------|----------|----------|
 70087 CAPHILL     115.00    | SINGL1 70039-701  |   109.4% |   109.5% |
 70148 DENVTM      115.00 1  | 08(1)             |   147MVA |   147MVA |
                             |                   |     (1x) |     (1x) |
-----------------------------|-------------------|----------|----------|
 70087 CAPHILL     115.00    | SINGL1 70039-701  |   100.4% |   101.8% |
 70276 MAPLETO1    115.00 1  | 08(1)             |   188MVA |   190MVA |
                             |                   |     (1x) |     (1x) |
-----------------------------|-------------------|----------|----------|
 70108 CHEROKEE_S  115.00    | SINGL1 70108-702  |   102.8% |   103.2% |
 70277 MAPLETO2    115.00 1  | 98(1)             |   168MVA |   168MVA |
                             |                   |     (1x) |     (1x) |
-----------------------------|-------------------|----------|----------|
 70134 CTY_LAM     24.900    | SINGL1 70134-701  |   102.0% |   102.0% |
 70136 CTY_LAM     69.000 T5 | 36(T4)            |    26MVA |    26MVA |
                             |                   |     (1x) |     (1x) |
-----------------------------|-------------------|----------|----------|
 70162 EAST        115.00    | SINGL1 70537-705  |   121.9% |   126.2% |
 70538 CHMBERS     115.00 1  | 38(1)             |   149MVA |   154MVA |
                             |                   |     (1x) |     (1x) |
-----------------------------|-------------------|----------|----------|
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13 2017  14:14              PAGE 32 .
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.                             AC CONTINGENCY REPORT FOR  2 AC CONTINGENCY CALCULATION
RUNS                             .
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                                 .
.           CONTINGENCY CASE MONITORED BRANCHES LOADED ABOVE 100.0% OF RATING SET A
- WORST CASE VIOLATIONS                .
.               % LOADING VALUES ARE % MVA FOR TRANSFORMERS AND % CURRENT FOR
NON-TRANSFORMER BRANCHES                     .
.               THRESHOLD FOR THE COUNT OF CONTINGENCIES CAUSING OVERLOADING IS
100.0% OF RATING SET A                 .
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                             |                   | 2038HS_p | 2038HS_C |
                             |                   | reCom3OU | om3OUT.a |
X--- MONITORED ELEMENT ----X | X-----LABEL----X  | T.acc    | cc       |
-----------------------------|-------------------|----------|----------|
 70214 GRANDJCT    69.000    | SINGL1 70076-700  |   107.8% |   107.6% |
 79034 GRANDJCT    115.00 T1 | 78(T5)            |    45MVA |    45MVA |
                             |                   |     (4x) |     (4x) |
-----------------------------|-------------------|----------|----------|
 70231 HOPKINS     115.00    | SINGL1 70296-703  |   158.8% |   158.8% |
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| | | | |
|---|---|---|---|
| 70267 HOPKINS 69.000 T1 | 88(1) | 59MVA (1628x) | 59MVA (1602x) |
| 70231 HOPKINS 115.00<br>79003 BASALT 115.00 1 | SINGL1 79003-790 04(T2) | 103.4% 87MVA (1x) | 103.4% 87MVA (1x) |
| 70245 LAGARITA 69.000<br>70325 PLAZA 69.000 1 | SINGL1 70230-703 76(1) | 102.3% 24MVA (1x) | 102.4% 24MVA (1x) |
| 70329 PORTLAND 69.000<br>70330 PORTLAND 115.00 T2 | SINGL1 70329-703 30(T1) | 108.9% 27MVA (1x) | 108.7% 27MVA (1x) |
| 70385 SHOSHA&B 4.0000<br>70386 SHOSHONE 69.000 U1 | SINGL1 70201-703 63(1) | 116.7% 8MVA (1x) | 116.6% 8MVA (1x) |
| 70385 SHOSHA&B 4.0000<br>70386 SHOSHONE 69.000 U2 | SINGL1 70201-703 63(1) | 121.6% 5MVA (1x) | 121.4% 5MVA (1x) |
| 70385 SHOSHA&B 4.0000<br>70386 SHOSHONE 69.000 U3 | SINGL1 70201-703 63(1) | 130.3% 8MVA (4x) | 130.2% 8MVA (4x) |
| 70472 WILOW_CK 115.00<br>70473 WILOW_CK 69.000 T1 | SINGL1 70472-704 73(T2) | 102.6% 43MVA (1x) | 102.4% 43MVA (1x) |
| 70472 WILOW_CK 115.00<br>70473 WILOW_CK 69.000 T2 | SINGL1 70472-704 73(T1) | 102.6% 43MVA (1x) | 102.4% 43MVA (1x) |
| 70630 RUSHCK2 345.00<br>70631 RUSHCK_W2 34.500 T1 | SINGL1 70311-731 92(1) | | 118.1% 567MVA (1610x) |

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. AC CONTINGENCY REPORT FOR 2 AC CONTINGENCY CALCULATION RUNS .
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.
. 'PSCO' CONTINGENCY CASE BUSES WITH VOLTAGE GREATER THAN 1.1000 - WORST CASE VIOLATIONS .
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| X--------- BUS ---------X | X-----LABEL----X | 2038HS_preCom3OUT.acc | 2038HS_Com3OUT.acc |
|---|---|---|---|
| 70825 CEDARCK_2A 34.500 | SINGL1 70825-708 28(1) | 1.10984 (1632x) | 1.10984 (1607x) |
| 70826 CEDARCK_2B 34.500 | SINGL1 70826-708 29(1) | 1.10675 (1x) | 1.10675 (1x) |

| | | | |
|---|---|---|---|
| 79123 FONTNLLE 4.2000 | SINGL1 7287-7319 6(1) | 1.14097 (1628x) | 1.14097 (1603x) |

CONTINGENCY LEGEND:
<----- CONTINGENCY LABEL ------> EVENTS
SINGL1 7287-73196(1) : OPEN LINE FROM BUS 7287 [LAZYDOG 115.00] TO BUS 73196 [TERRY 115.00] CKT 1
SINGL1 70825-70828(1) : OPEN LINE FROM BUS 70825 [CEDARCK_2A 34.500] TO BUS 70828 [DSTAT1_MV 34.500] CKT 1
SINGL1 70826-70829(1) : OPEN LINE FROM BUS 70826 [CEDARCK_2B 34.500] TO BUS 70829 [DSTAT2_MV 34.500] CKT 1
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. AC CONTINGENCY REPORT FOR 2 AC CONTINGENCY CALCULATION RUNS .

. 'PSCO' CONTINGENCY CASE BUSES WITH VOLTAGE LESS THAN 0.9000 - WORST CASE VIOLATIONS .
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| X--------- BUS ---------X | X-----LABEL----X | 2038HS_preCom3OUT.acc | 2038HS_Com3OUT.acc |
|---|---|---|---|
| 70092 CENTER 69.000 | SINGL1 70230-70376(1) | 0.88669 (1x) | 0.88554 (1x) |
| 70201 GLENNWD 69.000 | SINGL1 70201-70363(1) | 0.82776 (1x) | 0.82714 (1x) |
| 70229 HOOPER 69.000 | SINGL1 70230-70376(1) | 0.88305 (1x) | 0.88189 (1x) |
| 70230 HOOPERTP 69.000 | SINGL1 70230-70376(1) | 0.88609 (1x) | 0.88493 (1x) |
| 70288 MITCHLCR 69.000 | SINGL1 70201-70363(1) | 0.83004 (3x) | 0.82943 (4x) |
| 70296 NEWCASTL 69.000 | SINGL1 70296-70388(1) | 0.88310 (3x) | 0.88254 (3x) |
| 70386 SHOSHONE 69.000 | SINGL1 70201-70363(1) | 0.84741 (1x) | 0.84681 (1x) |
| 70388 SILTUSBR 69.000 | SINGL1 70359-70388(1) | 0.88409 (1x) | 0.88354 (1x) |
| 71007 BUSCHRNCH2 34.500 | SINGL1 73011-73488(1) | 0.45091 (1634x) | |
| 71007 BUSCHRNCH2 34.500 | SINGL1 79042-79050(1) | | 0.44661 (1609x) |
| 71008 BUSCHRNCH1 34.500 | SINGL1 73011-734 | 0.47925 | |

| | | | |
|---|---|---|---|
| | 88(1) | (1634x) | |
| 71008 BUSCHRNCH1 34.500 | SINGL1 79042-790 50(1) | | 0.47475 (1609x) |
| 71009 BUSCHRWTG1 0.6900 | SINGL1 70415-704 22(1) | | 0.14779 (1609x) |
| 71009 BUSCHRWTG1 0.6900 | SINGL1 73011-734 88(1) | 0.14691 (1634x) | |
| 73525 BELLECRK 69.000 | SINGL1 73525-740 51(1) | 0.86163 (2x) | 0.86171 (2x) |
| 73527 BUTTEPMP 69.000 | SINGL1 73525-740 51(1) | 0.88547 (2x) | 0.88554 (2x) |

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. AC CONTINGENCY REPORT FOR 2 AC CONTINGENCY CALCULATION RUNS .

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. 'PSCO' CONTINGENCY CASE BUSES WITH VOLTAGE LESS THAN 0.9000 - WORST CASE VIOLATIONS .

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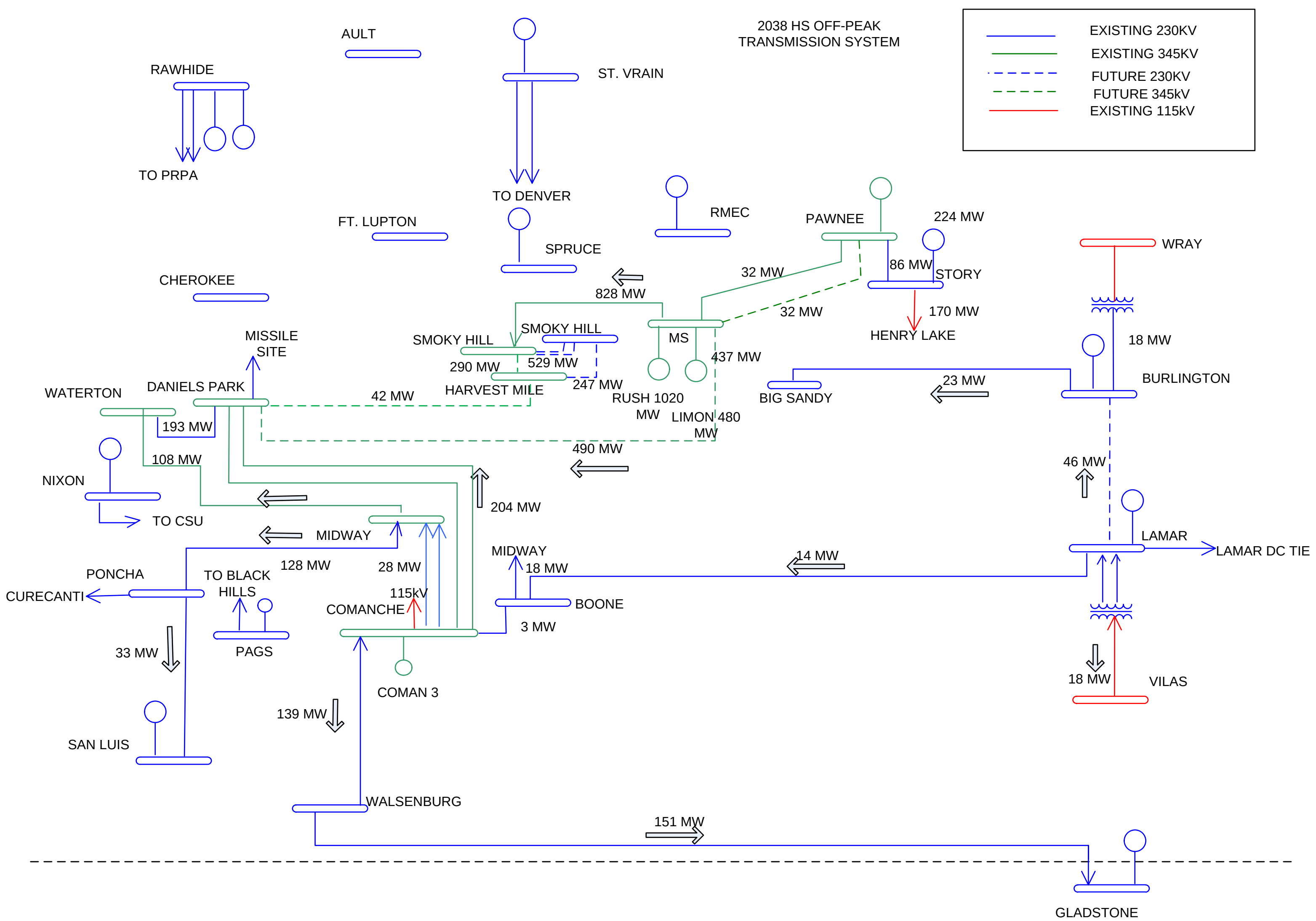
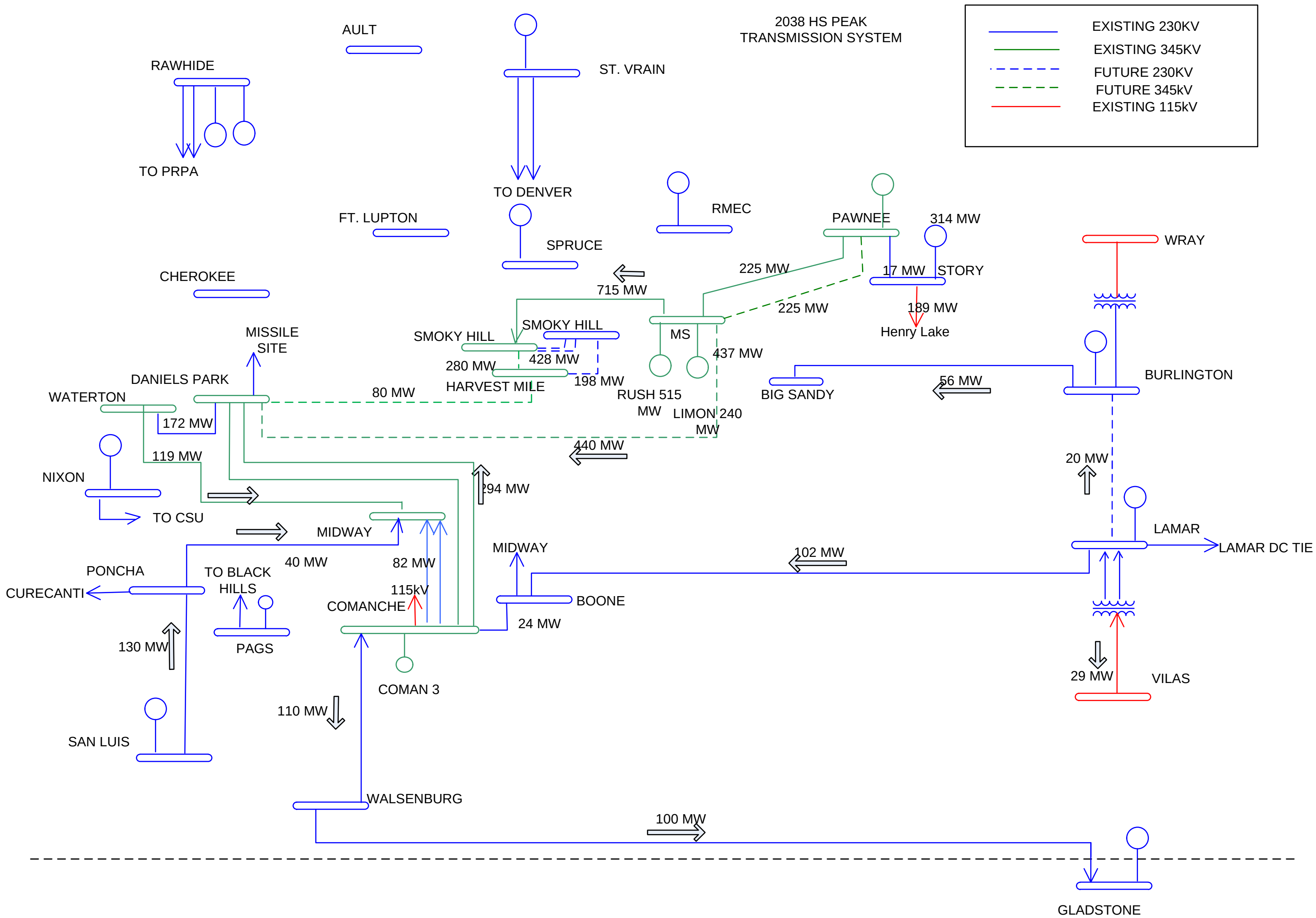
| X--------- BUS ---------X | X-----LABEL----X | 2038HS_preCom3OUT.acc | 2038HS_Com3OUT.acc |
|---|---|---|---|
| 74050 DENBURY 69.000 | SINGL1 73525-740 51(1) | 0.86071 (2x) | 0.86079 (2x) |
| 74051 BC_DVAR 25.000 | SINGL1 74051-740 53(1) | 0.86163 (1x) | 0.86171 (1x) |
| 79008 GRANGER 69.000 | SINGL1 79008-790 30(1) | 0.77843 (3x) | 0.77843 (3x) |
| 79009 LYMAN SW 69.000 | SINGL1 79008-790 09(1) | 0.76611 (4x) | 0.76611 (4x) |
| 79030 FONTNLLE 69.000 | SINGL1 79030-791 23(1) | 0.78603 (2x) | 0.78603 (2x) |
| 79123 FONTNLLE 4.2000 | UNIT 79123(1) | 0.81997 (1x) | 0.81997 (1x) |
| 73403 RD_NIXON 34.500 | SINGL1 73388-734 04(1) | 0.30402 (1635x) | 0.30325 (1609x) |
| 73401 KELKER E 34.500 | SINGL1 70138-701 39(T1) | | 0.30802 (1609x) |
| 73401 KELKER E 34.500 | SINGL1 73420-734 22(1) | 0.30876 (1634x) | |



2038 HS OFF-PEAK
TRANSMISSION SYSTEM
EXISTING 230KV
EXISTING 345KV
FUTURE 230KV
FUTURE 345kV
EXISTING 115kV
AULT
RAWHIDE
TO PRPA
ST. VRAIN
TO DENVER
FT. LUPTON
SPRUCE
RMEC
PAWNEE
224 MW
86 MW
STORY
32 MW
32 MW
170 MW
HENRY LAKE
WRAY
18 MW
BURLINGTON
CHEROKEE
828 MW
MS
SMOKY HILL
SMOKY HILL
290 MW
529 MW
247 MW
HARVEST MILE
437 MW
RUSH 1020 MW
LIMON 480 MW
BIG SANDY
23 MW
MISSILE SITE
DANIELS PARK
WATERTON
42 MW
193 MW
490 MW
108 MW
NIXON
TO CSU
204 MW
46 MW
MIDWAY
LAMAR
LAMAR DC TIE
MIDWAY
18 MW
14 MW
PONCHA
128 MW
28 MW
CURECANTI
TO BLACK HILLS
115kV
COMANCHE
BOONE
3 MW
33 MW
PAGS
COMAN 3
18 MW
VILAS
139 MW
SAN LUIS
WALSENBURG
151 MW
GLADSTONE


2038 HS PEAK
TRANSMISSION SYSTEM
EXISTING 230KV
EXISTING 345KV
FUTURE 230KV
FUTURE 345kV
EXISTING 115kV
AULT
RAWHIDE
TO PRPA
ST. VRAIN
TO DENVER
FT. LUPTON
SPRUCE
RMEC
PAWNEE
314 MW
WRAY
CHEROKEE
225 MW
17 MW
STORY
715 MW
225 MW
189 MW
Henry Lake
MISSILE
SITE
SMOKY HILL
SMOKY HILL
MS
437 MW
428 MW
280 MW
198 MW
HARVEST MILE
RUSH 515
MW
LIMON 240
MW
BIG SANDY
56 MW
BURLINGTON
DANIELS PARK
80 MW
WATERTON
172 MW
440 MW
119 MW
NIXON
294 MW
20 MW
TO CSU
MIDWAY
LAMAR
LAMAR DC TIE
MIDWAY
40 MW
82 MW
102 MW
PONCHA
TO BLACK
HILLS
CURECANTI
115kV
COMANCHE
BOONE
24 MW
130 MW
PAGS
29 MW
VILAS
COMAN 3
110 MW
SAN LUIS
WALSENBURG
100 MW
GLADSTONE