# RENEWABLE ENERGY DEVELOPMENT INFRASTRUCTURE PROJECT

# COLORADO GENERATION AND TRANSMISSION

# BASELINE ASSESSMENT

**NAVARRO-E2MG**

**UNDER A CONTRACT**
**FROM**
**COLORADO GOVERNOR'S ENERGY OFFICE**

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## Terminology

**Watt:** a unit of electrical power

**kW, MW, GW**: electrical power generated or consumed: 1 kilowatt (kW) = 1,000 watts, 1 Megawatt (MW) = 1,000 kW = 1 million watts, and 1 Gigawatt (GW) = 1,000 MW = million kW = billion Watts

**Watt hour:** electrical energy equal to one Watt of power consumed or generated for one hour **kWh, MWh, GWh:** 1 Kilowatt hour, 1 Megawatt hour, 1 Gigawatt hour, respectively, consisting of 1,000 watt hours, 1 million watt hours, and 1 billion watt hours

**Renewable energy resources:** energy resources, which naturally replenish in a relatively short period of time, such as solar energy, geothermal energy, wind energy, biomass, and hydropower

**Energy efficiency:** actions or measures which reduce energy used for various services such as space cooling, refrigeration, lighting, torque, etc., without degrading the quality of the services provided, sometimes called demand-side management (DSM)

**Must Run:** Generation designated to operate at a specific level and not available for dispatch

**Base:** Generation designated to operate around the clock at varying dispatch levels

**Peaking:** Generation designated to operate as dispatched during peak hours.

**Cycling:** Generation designated to operate as dispatched to cycle up and down on hourly or sub-hourly basis to compensate for other generation varying units

**Open-Access Same-Time Information System (OASIS)—** An electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously

**Contract Path**—Specific contiguous electrical path from a point of receipt to a point of delivery for which transfer rights have been contracted.

**Control Area**—Electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection

**Facilities Study -** An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications that will be required to provide the requested transmission service.

**Network Customer -** An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Open Access Transmission Tariff (OATT).

**Network Integration Transmission Service -** The transmission service provided under OATT.

**Network Resource -** Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

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**Network Upgrades -** Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

**Reserved Capacity -** The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

**Service Agreement -** The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

**System Impact Study -** An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To- Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

**Transmission Customer -** Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under the Tariff.

**Transmission Provider -** The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

**Transmission Service -** Point-To-Point Transmission Service provided under Tariff on a firm and non-firm basis.

**Transmission System -** The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under the Tariff.

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## 1. Introduction

This portion of the REDI report looks at Colorado’s generation and transmission infrastructure by examining the existing power system, and the factors involved in achieving maximum economic and societal benefits from electricity production from conventional and renewable resources. In addition to traditional considerations of fuel type and generation capacity, policymakers today must take into account the effects of Renewable Energy Standards (RES), Colorado’s Climate Action Plan (CAP), and various measures to improve energy efficiency and implement demand-side management programs.

On the generation front, significant progress is being made by the regulated utilities and to some degree by non-regulated utilities, to meet the goals of RES and the Colorado Governor’s CAP through resource planning. However, reaching the CAP’s goals by 2020 requires a large-scale shift to clean energy integration from Renewable Energy Zones (REZ). A successful large-scale shift to clean energy, demands a bold commitment by utilities, regulators, and policymakers to provide infrastructure and new rules that enable power from REZs that are often remotely located, to be delivered to consumers efficiently and economically. Based on our in-depth assessment and projections, we show several possible pathways Colorado could take to achieve sustainable energy production and minimize harmful emissions and potential new carbon regulation in the future provided there is adequate transmission infrastructure built in time.

On the transmission front, there is growing indication that the transmission system in Colorado is stressed and is in urgent need of expansion. Over the years, Colorado transmission system has become congested, because growth in electricity demand and investment in new generation facilities have not been matched by investment in new transmission facilities. Because the existing transmission system was not designed to bring renewable resources from newly designated Generation Development Areas (GADs) to load, continued delay in transmission investment in Colorado will further delay meeting

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the requirements of the RES and Colorado CAP and increase electricity costs to consumers and reduce the reliability of the power system.

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## 2. Electricity Generation

There are two types of resources available to Colorado utilities for meeting demand and energy requirements of their customers. Supply-side resources provide generation capacity to serve load, whereas demand side resources act to reduce the level of customer demand for electric power so fewer supply-side resources need to be built. Supply-side resources are generally categorized into two main categories: traditional (or thermal) and renewable. Conventional supply-side resources are typically fossil fuel based generation resources with physical fuel supplies. In contrast, renewable resources are supply-side generation resources from renewable resources or elemental fuel supplies.

The conventional supply-side resources are generally represented by peaking, intermediate and baseload units. Peaking units are generally combustion turbines ("CT") that operate in simple cycle using natural gas as source of fuel. The CT units are available in a wide range of sizes (25-300 MW). The principle role for peaking units is to be run for a few hours of the year typically during the highest electric demand hours since combustion turbines have rapid ramp rates usually less than 10 minutes. CTs are typically inexpensive, in terms of over night construction costs to build, but are relatively inefficient (i.e., high heat rate) sources of generation. CTs are expensive to run, and for that reason they operate only a few numbers of hours in the year. On the other hand, Intermediate units are generally Combined Cycle (“CC”) units. Combined Cycle units are more efficient natural gas fired facilities that could use single or multiple CTs in conjunction with a Heat Recovery Steam Generator (HRSG). The waste heat from CT's exhaust gas is used to generate steam through HRSG to run a steam turbine which in turn produces additional electric power. Combined Cycle units have also high ramp rates and come in a variety of sizes (100-700 MW) depending on the specific configuration of the facility. CCs have higher over night construction costs to be built than CTs, but have lower operating costs due to higher efficiencies (i.e., lower heat rate). Since both technologies, CTs and CCs, use natural gas to generate, their production costs, delivered price of electricity, is determined largely by the cost of natural gas which has been very volatile source of fuel.

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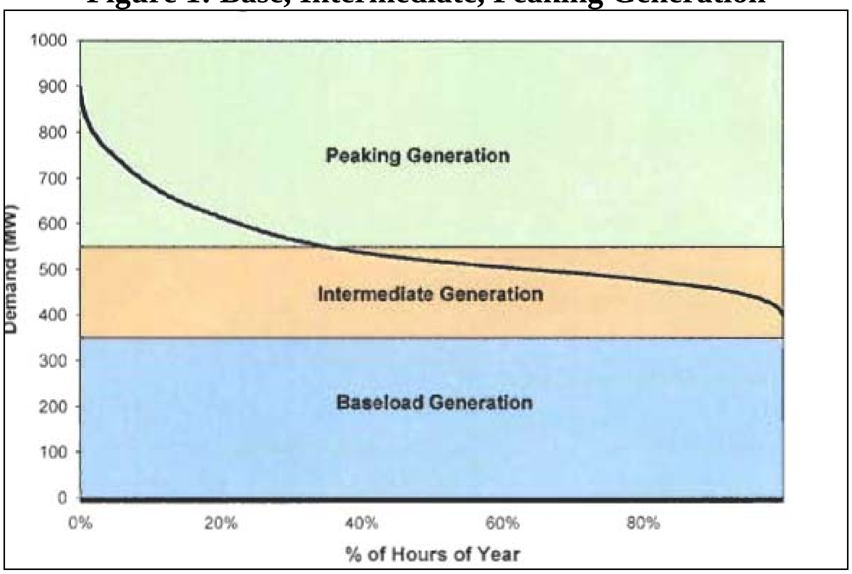
Baseload units are designed to run continuously around the clock except when shut down for planned scheduled maintenance. Baseload units have the highest over night construction costs to build but the lowest fuel costs. Typically baseload units' burn coal or nuclear fuel and have much lower ramp rate compared to CTs and CCs. Different thermal generation technologies (peaking, intermediate, baseload) have different operating cost characteristics. These characteristics dictate how these technologies are economically dispatched to serve load requirements of the system. Figure 1 illustrates an electric system that is short of baseload resources, which will cause the system to operate some of its intermediate resources in a baseload mode that operates around the clock.

**Figure 1: Base, Intermediate, Peaking Generation**




Source: PSCo 2007 Colorado Resource Plan (CRP)

Figure 1 also shows the load duration curve, which provide a graphical representation of how electric supply resources would operate to serve both the demand and energy requirements of the system. A load duration curve contains the total energy requirements of the system (typically over an entire year), sorted from the highest use hours to the lowest use hours. The highest number on the left hand side of the curve represents a peak energy usage served by CTs during the highest energy demand day. The numbers on the right hand side generally represent overnight hours when energy demand is low. By overlaying the generation stack on top of the load duration curve, one can show

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how much electric power each resource type (i.e., Baseload, Intermediate, and Peaking) would be required to produce over the year.

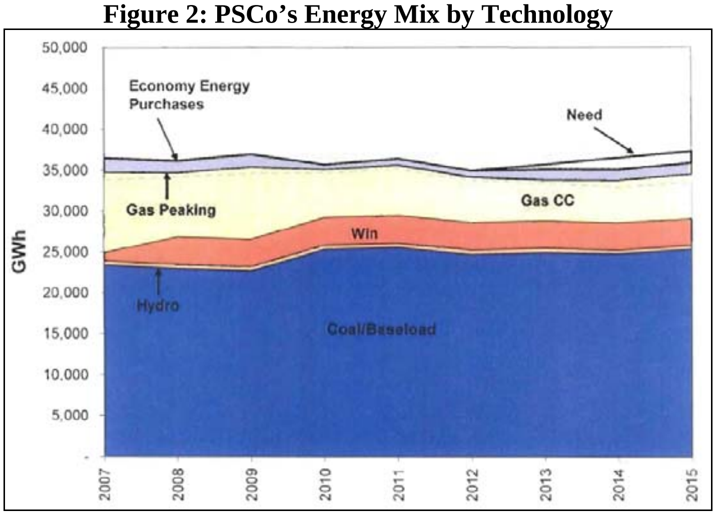
**Table 1: Capital & Operating Costs Comparison of Thermal Units & Wind**

| COSTS | GAS CT | GAS CC | COAL STEAM | NUCLEAR | WIND |
|---|---|---|---|---|---|
| Capital Costs | Low | Medium | High | High | Medium/High |
| Fuel Costs | High | Medium | Low | Low | Zero |
| Utilization | Peaking | Intermediate | Baseload | Baseload | Varies |
| Hours of Use | Low | Medium | High | High | Varies |
| CO2 | Medium | Medium | High | Zero | Zero |

Source: PSCo 2007 CRP – added Wind Column

As shown in Table 1, the costs of resources are generally compared with one another based on how they are utilized (i.e., peaking, intermediate, or baseload) on the system. The overall cost, "all-in" cost, of electric energy per MWh depends on the unit's capacity factor.[1] As the fixed costs (capital, operations and maintenance costs) are distributed over more hours of operation, the levelized cost decline.[2] Figure 2 below shows how PSCo is planning to fill its forecasted energy needs by different generation technologies and fuel type.

**Figure 2: PSCo's Energy Mix by Technology**




Source: PSCo's 2007 Colorado Resource Plan

Figure 2 shows the energy mix generated by various technologies and fuel type. Coal based generation represents about two third of total generation followed by gas fired

[1] Capacity Factor is defined as the average load of the generating unit as a percentage of rated capacity.
[2] Fuel costs are included as part of operation costs.

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generation (i.e., CCs and CTs), wind, purchased power, and hydro in descending order. Wind generation increases rapidly from 2007 to 2009 and stays the same level through out the given years. Coal based generation also increases from 2009 to 2010 due to PSCo's Comanche 3 becoming operational in late 2009. Figure 2 also shows the diminishing amount of gas generation due to increased wind and coal generation to meet PSCo's load requirements in out years.

Table 2 depicts Colorado Net Generation percent share by fuel in five-year increments from 1990 to 2005. In 1990, about 92% of Colorado net power generation was from coal-fired generating power plants, 4% from gas-fired generation, and the remainder was from hydroelectric and oil generation. Due to the economic expansion of the last decade, Colorado experienced a high growth in use of electricity which resulted in a surge of installed gas-fired generation capacity to meet the increased demand. In 2005, power generation from gas-fired units increased to 24% of Colorado net power generation, while generation from coal-fired met about 72% of Colorado net power generation.

**Table 2: Colorado Net Generation by Fuel Type (1990-2005)**

| Fuel Type | 1990 (MWh) | 1995 (MWh) | 2000 (MWh) | 2005 (MWh) | Average Annual Growth Rate (%) | 1990 Share (%) | 1995 Share (%) | 2000 Share (%) | 2005 Share (%) |
|---|---|---|---|---|---|---|---|---|---|
| **Coal** | 29,814,983 | 30,492,682 | 35,381,219 | 35,570,135 | 1.3% | 91.6% | 85.6% | 80.1% | 71.7% |
| **Oil** | 27,390 | 11,712 | 109,385 | 17,046 | -2.5% | 0.1% | 0.0% | 0.2% | 0.0% |
| **Natural Gas** | 1,290,092 | 2,856,788 | 7,157,438 | 11,923,290 | 54.9% | 4.0% | 8.0% | 16.2% | 24.0% |
| **Other Gas** | 0 | 0 | 0 | 2,430 | - | 0.0% | 0.0% | 0.0% | 0.0% |
| **Hydro** | 1,419,870 | 2,131,189 | 1,454,415 | 1,415,296 | 0.0% | 4.4% | 6.0% | 3.3% | 2.9% |
| **Renewable** | 28,990 | 32,910 | 17,914 | 810,561 | 179.7% | 0.1% | 0.1% | 0.0% | 1.6% |
| **Pump Storage** | -33,198 | 91,953 | 45,175 | -122,063 | 17.8% | -0.1% | 0.3% | 0.1% | -0.2% |
| **Total Generation** | 32,548,127 | 35,617,234 | 44,165,546 | 49,616,695 | 3.5% | 100.0% | 100.0% | 100.0% | 100.0% |

Source: DOE/EIA

In 2004, Colorado's Renewable Energy Standard (RES) was enacted through voter initiative "Amendment 37" followed by legislative action in 2007, passage of House Bill 1281, which revised and extended the 2004 RES requirements for rate regulated utilities (i.e., PSCo and Black Hills) from 10% to 15% by 2015, and to 20% by 2020 and thereafter. Under the new legislation, Cooperatives and Municipally owned utilities are also required to include renewable energy in their resource portfolio however, to a lesser

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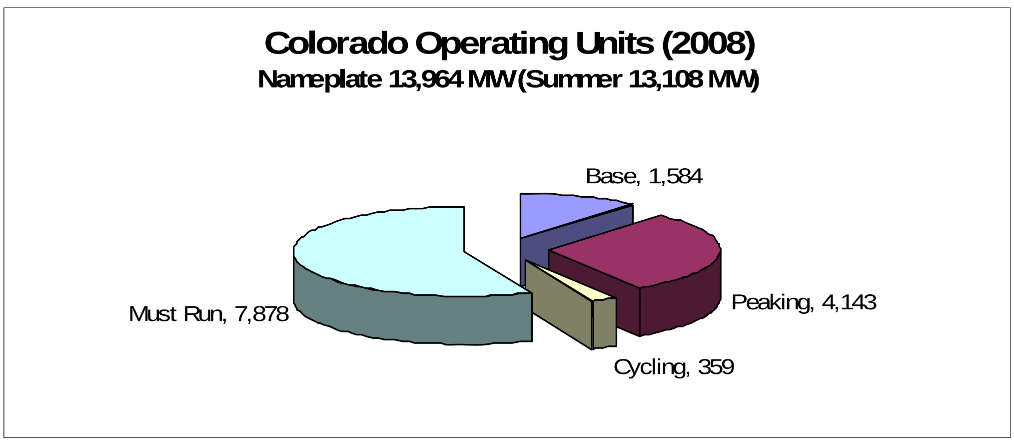
extent than rate regulated utilities (e.g., 10% of retail sales by 2020 vs. 20% for rate regulated utilities). The law applies to each provider of retail electric service in the state of Colorado other than Municipally Owned utilities that serve forty thousand customers or less. These initiatives have changed the resource portfolio of Colorado utilities with more integration of renewable resources into their resource portfolio.

As of 2008, Colorado has an estimated 13,964 MW of installed nameplate capacity (Summer Capacity of 13,108 MW) of which 7,878 MW is categorized as Must Run, 1,584 MW as Base, 4,143 MW as Peaking, and 359 MW as Cycling capacities.[3] Must Run units include all coal-fired units and most of the CC units. Base units include all hydro and wind units while Peaking covers all CT units. Cycling units include a few CTs and Steam units (e.g., PSCo's Zuni gas-fired Steam units or Brush Cogeneration units). See Figure 3 below.

**Figure 3: Colorado Operating Thermal and Renewable Units**




Source: Energy Velocity

As a result of load growth forecast and the Colorado Public Utilities Commission's Electric Resource Planning process, there is about 5,570 MW of new capacity planned to

[3] Generating units are categorized in the dispatch merit order as; Must Run, Base, Peaking, or Cycling units. Must Run is categorized as generation designated to operate at a specific level and not available for dispatch, Base is categorized as generation designated to operate around the clock at varying dispatch levels, Peaking is generation designated to operate as dispatched during peak hours, and Cycling is generation designated to operate as dispatched to cycle up and down on hourly or sub-hourly basis to compensate for other generation varying units.

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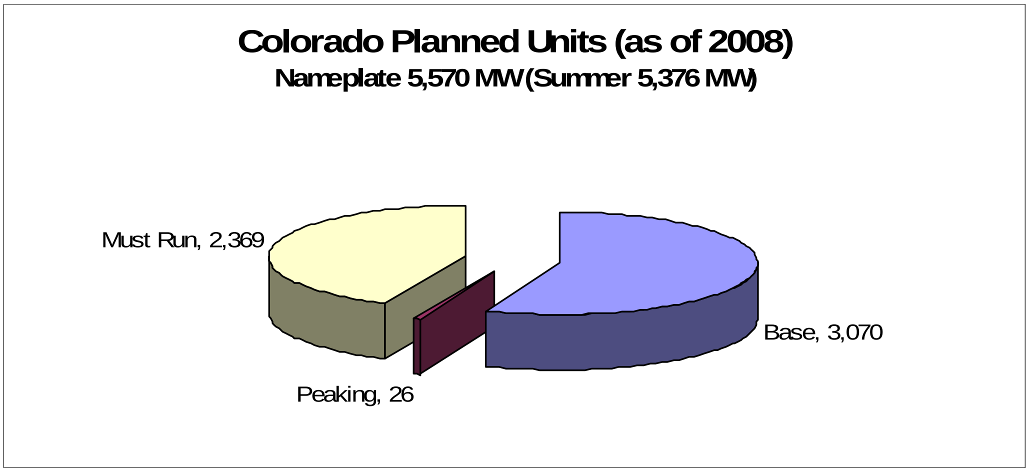
be installed in the next 6 years of which 2,369 MW will be categorized Must Run units, 3,070 MW of Base units, and 26 MW of Peaking units. See Figure 4 below.

**Figure 4: Colorado Planned Capacity Additions**




Source: Energy Velocity

Renewable resources, in particular, wind and solar are playing an increasing role in Colorado utilities' resource portfolio. About 55% of all new planned capacity in Colorado for the next 6 years (2009-2015) is from renewable resources categorized to be operated as Base units; 2,050 MW from wind resources and about 1,000 MW from solar technologies. Appendix A provides the list of all existing operating and planned generating units in Colorado.

Utility resource planners use a range of approaches to identify the amounts, timing, and types of generation resources that need to be added to meet the forecasted demand for electric power. One basic tool is a Loads and Resource Table ("L&R"). The function of an L&R Table is to provide a comparison between the amount of electric generating supply and the peak load of a system. In years when load plus added reserve margin exceeds generation supply, additional generation suppliers are needed. Another tool to use is computer models known as capacity expansion models. Electric capacity expansion planning models determine the optimal investments (plants and capacity levels) over the

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planning horizon (up to 40 years into the future). For example, PSCo recently completed its 2007 electric resource planning cycle and determined a number of resource portfolios, and proposed one as a preferred plan to the Commission. Table 3 shows PSCo's Proposed Resource Plan Scenarios with In-Service Date of 2015 for 2,365 MW of capacity need of which 800 MW is allocated to wind, 225 MW to solar and the remaining 1,340 MW to gas-fired generation (i.e., 950 MW CC and 390 MW CT).

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**Table 3: PSCo's Proposed Resource Plan Scenarios with In-Service Date of 2015**

| Proposed PSCo CRP (in 2015) | |
|---|---|
| Gen | MW |
| Wind | 800 |
| Solar | 225 |
| Arapahoe CC | 480 |
| New CT (3) | 390 |
| New CC | 470 |
| | |
| Total | 2,365 |

Assumptions:

- High Wind = 150% of CRP = 1200 MW
- High Solar = 200% of CRP = 450 MW
- The High Solar will offset one gas CT (130 MW)

| Base Case Plan (PSCo Preferred Resource Plan) | | | *Scenario 1* |
|---|---|---|---|
| Gen | MW | Location | ERZ |
| Wind | 400 | Pawnee | Zone 1 |
| Wind | 200 | Baca | Zone 3 |
| Wind | 200 | Comer Point | Zone 2 |
| Solar | 200 | San Luis Valley | Zone 4 |
| Solar | 25 | Boone | Zone 5 |
| Arapahoe CC | 480 | Arapahoe | Denver Metro |
| New CT 1 | 260 | Spruce Extension | Existing |
| New CT 2 | 130 | Pawnee | Zone 1 |
| New CC 1 | 470 | RMEC Extension | Existing |
| | | | |
| Total | 2,365 | | |

| High Wind North (Zones 1 and 2) | | | *Scenario 2* |
|---|---|---|---|
| Gen | MW | Location | ERZ |
| Wind | 600 | Pawnee | Zone 1 |
| Wind | 200 | Ault | Zone 1 |
| Wind | 400 | Comer Point | Zone 2 |
| Solar | 200 | San Luis Valley | Zone 4 |
| Solar | 25 | Boone | Zone 5 |
| Arapahoe CC | 480 | Arapahoe | Denver Metro |
| New CT 1 | 260 | Spruce Extension | Denver Metro |
| New CT 2 | 130 | Comer Point | Zone 2 |
| New CC 1 | 470 | RMEC Extension | Existing |
| | | | |
| Total | 2,765 | | |

| High Solar | | | *Scenario 3* |
|---|---|---|---|
| Gen | MW | Location | ERZ |
| Wind | 400 | Pawnee | Zone 1 |
| Wind | 200 | Baca | Zone 3 |
| Wind | 200 | Comer Point | Zone 2 |
| Solar | 400 | San Luis Valley | Zone 4 |
| Solar | 50 | Boone | Zone 5 |
| Arapahoe CC | 480 | Arapahoe | Denver Metro |
| New CT 1 | 260 | Spruce Extension | Existing |
| New CT 2 | 0 | | |
| New CC 1 | 470 | Comer Point | Zone 2 |
| | | | |
| Total | 2,460 | | |

| High Wind South (Zones 3 and 5) | | | *Scenario 4* |
|---|---|---|---|
| Gen | MW | Location | ERZ |
| Wind | | | |
| Wind | 800 | Baca | Zone 3 |
| Wind | 400 | Walsenburg | Zone 5 |
| Solar | 200 | San Luis Valley | Zone 4 |
| Solar | 25 | Boone | Zone 5 |
| Arapahoe CC | 480 | Arapahoe | Denver Metro |
| New CT 1 | 260 | Spruce Extension | Denver Metro |
| New CT 2 | 130 | Comer Point | Zone 2 |
| New CC 1 | 470 | Pawnee | Zone 1 |
| | | | |
| Total | 2,765 | | |

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## 3. Generation and Voltage Control

The concept of optimum dispatch and scheduling of generating units requires a control mechanism over the generating units. There are many generators supplying power into the transmission system, with each generating unit's speed maintained with a governor while supplementary controls, usually at a remote control center, act to control and allocate generation as load changes. The name Automatic Generation Control (AGC) is given to a control system that controls and achieves three major objectives:

1. Hold system frequency at or very close to a specified nominal value (e.g., 60 Hz)
2. Maintain the correct value of interchange power between control areas
3. Maintain each unit's generation at the most economic value.

Another element that is controlled and regulated in the power system is voltage regulation. Voltage regulators control the flow of reactive power in the system. In an alternating current (AC) system, when the current lags on the voltage waveform, it transmits less power than when it is in phase. The apparent power is the product of voltage by current, but the real power is less that this by the power-factor percentages. The apparent power is represented by two vector components – real power and reactive power. Both components are important in power generation and must be metered and controlled separately. The power factor is a way of representing the extent to which alternating current drawn by the plant is out of phase with the voltage. It is expressed as the ratio (or percentage) of real power (watts) to apparent power (volts x amperes). Most industrial plants draw a lagging current and have a power factor somewhere between 70 and 95 percent. The power factor becomes harder to understand once an in-plant generator is interconnected and operated in parallel with the utility network because the power factor (or reactive power flow) is closely tied in with the voltage control of the plant generator and the voltage of the utility supply.

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Utilities are concerned about reactive current – the component of total current that is 90 degree out of phase with the voltage which leads to the concept of reactive power, normally expressed in volts-amperes reactive or VARS. System operators are concerned with the flow of watts and the flow of VARS. The power output of a generator is controlled by varying the torque applied to its shaft by the prime mover. The VARS output is controlled by varying the excitation (the production of a magnetic field in a generator or motor by passing electricity through the coil). For example, if an in-plant generator is overexcited, it produces VARS as well as watts, and these VARS flow into the plant's motors to provide their excitation current. This flow reduces the amount of VARS that the motors draw from the utility system. It is exactly the same as installing power-factor correction capacitors to correct poor power factor in a plant, the generator functions as a synchronous capacitor.

The voltage at which a utility supplies power to a plant is held within +/-5% of the nominal value. In practice, it varies with the load on the utility's transmission line and the distance of the plant from the nearest substation.

## 4. Transmission and Wind Integration

In its recent publication, the DOE identified two separate and distinct power system challenges to obtaining 20% of electric energy from wind.[4] The study references the challenges as:

> "…One challenge lies in the need to reliably balance electrical generation and load over time when a large portion of energy is coming from a variable power source such as wind, which, unlike many traditional power sources, cannot be accessed on demand or is "nondispatchable." The other challenge is to plan, build, and pay for the new transmission facilities that will be required to access remote wind resources."

[4] DOE, 2008. *20% Wind Energy by 2030*. Available at: http://www.osti.gov/bridge

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## Wind Integration in Colorado

The largest utility in Colorado, PSCo, has undertaken major studies under the Commission Order in Docket No. 04A-325E to determine the level of wind energy integration into its system.[5] The objective of the *Wind Integration Study* was to assess the costs that would be incurred by PSCO for taking the delivery of the amounts of wind generation specified in the Commission Order. The Commission Order specified two levels of wind integration to be studied:

1- 10% "penetration" (the ratio of installed wind generation capacity to projected hourly peak load for the 2007 study year) which translated into 722 MW of installed wind capacity for the PSCo system
2- 15% penetration, or 1038 MW installed wind capacity

The Commission Order required PSCo to evaluate costs associated with integration of 20% wind penetration or 1444 MW as to report in its 2007 Resource Plan. PSCo deferred the 20% wind penetration study to a later date due to wind generation forecast accuracy, operational practice during periods of high wind generation and low load, and sensitivity of integration costs to assumptions and input data. In December 2008, PSCo filed its 20% wind study with the Commission. Results of 10%, 15%, and 20% study are shown in Table 4.

**Table 4: Study Results of Wind Integration Costs for PSCo's System**

| Wind Penetration | Electric Production Cost Differential ($/MWh) |
|---|---|
| 10% | 2.25 |
| 15% | 3.25 |
| 20% | 8.56 |

[5] PSCo, 2006. *Wind Integration Study*, Final Report, May. Available at: http://www.nrel.gov/wind/systemsintegration/pdfs/colorado_public_service_windintegstudy.pdf

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Wind integration costs shown in Table 4 are used in PSCo's resource planning process. The integration costs are added to the levelized cost of wind bid proposals and are compared with other bid proposals for competiveness. These costs are derived from so called "cycling costs" of other units within PSCo's generation fleet to compensate for the intermittency of wind generation. As indicated earlier, the cycling units are generally gas-fired generating units that operate to cycle up and down on hourly or sub-hourly basis to compensate for other generation varying units in this case wind.

## 5. Intermittent Generation and Energy Storage

Intermittent energy sources such as wind require energy storage capacity if they are to provide consistent, on-demand power to the grid, and be able to replace traditional fossil fueled sources in large scales. As the penetration of intermittent energy sources increases toward 20% and higher, utilities and wind developers show interest that some method to store and deploy electricity on demand which would enhance the value of wind will be needed. Energy storage serves as a bridge between the limited, variable generation capability of energy sources and the highly variable, cyclical grid demand. Energy storage can be implemented as a buffer to match the available generation to the variable user demand.

Recent research conducted at the University of Colorado has shown that there are several good options for energy storage in Colorado, and many sites currently exist where these energy storage technologies could be implemented.[6] For example, Hydro Pumped-Storage facilities such as Cabin Creek and Mt. Elbert provide energy storage in Colorado with a number of significant benefits to the reliable and cost-effective operation of the electric system including quick start capability (less than 10 minutes to full capacity). Fast

[6] Large Scale Electrical Energy Storage in Colorado, Available at: www.colorado.edu/engineering/energystorage

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ramp rate, multiple starts/stops capability without maintenance penalty, and valuable regulation and spinning reserves capability (either pumping or generating mode).

The study on Large Scale Electrical Energy Storage provides detailed information on three energy storage technologies for Colorado:

1. Pumped Hydroelectric Energy Storage
2. Underground Pumped Hydroelectric Energy Storage
3. Compressed Air Energy Storage

The study cites the benefit of two existing pumped storage plants in Colorado (Cabin Creek and Mt. Elbert), and references the documented benefit of the plants on the utility system, particularly with wind integration. In addition, the research provides information on eight more potential sites for additional pumped hydroelectric plants with detailed analyses. The research uses a model that was developed to analyze both economic and technical characteristics of each site. Based on detailed site studies, the research recommended that the West Gypsum and the Horsetooth-College sites be prioritized for detailed cost benefit analyses. Table 5 provides a summary of the site names, power, energy, and estimated pay-back period.

**Table 5: Summary of Pumped Hydroelectric Potential in Colorado**

| Site Name | MW | MWh | Payback (years) |
|---|---|---|---|
| Cabin Creek as Calculated | 329 | 1317 | 39 |
| Bellyache Ridge | 310 | 2167 | 21 |
| West Gypsum | 375 | 2622 | 21 |
| Horsetooth College | 15 | 75 | 33 |
| Davis Pt | 548 | 2739 | 25 |
| Schoolhouse Pt | 630 | 3148 | 25 |
| Peetz Bluffs | 43 | 213 | NA, does not payback in base calculation |
| Gunnison Hydro | 641 | 3846 | 22 |

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The study also refers to the Colorado agricultural sector as a source of renewable energy by proposing an economical and minimal impact energy storage system. The proposed system is an adaptation of pumped hydroelectric energy storage that uses a surface reservoir and an underground aquifer to pump water up and down aquifer. The system would utilize much of the existing infrastructure in agricultural operations, including the irrigation well, irrigation boost pumps, and any available surface reservoir. The research cites the limitations in applicability of the underground pumped hydro storage system because high percentage of irrigation water in Colorado is drawn from surface sources and only a small percentage have sufficient depth to water differentials to accommodate a reasonable underground pumped hydro storage system. However, two regions in Colorado are identified that have the most potential wells for this concept; the San Luis Valley and the northeastern High Plains. The concept requires a well with a minimum of about 150 feet of hydraulic head and a high flow rate (greater than 1500 gpm). See Figure 5 below.

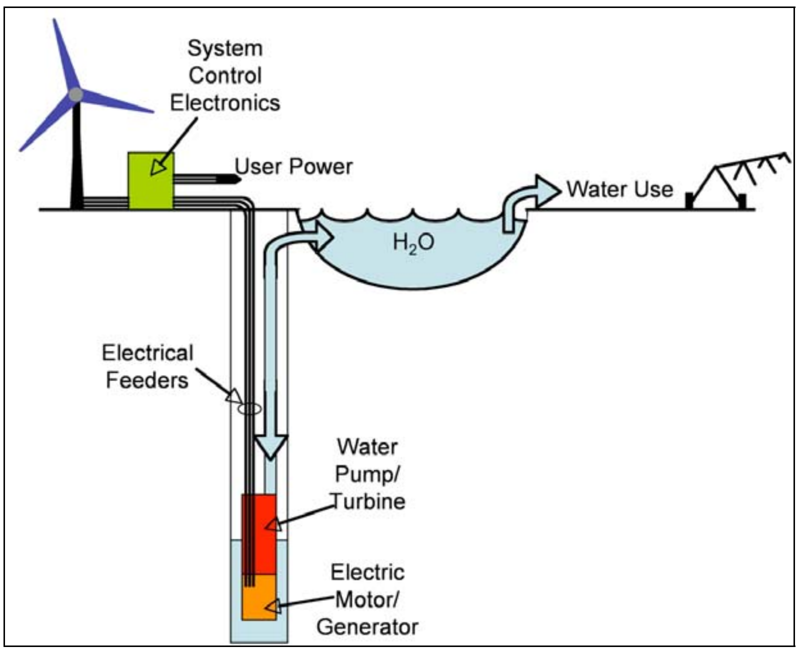


**Figure 5: Aquifer Underground Pumped Hydroelectric Energy Storage**

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Another technology recommended by the study is compressed air energy storage as a good option for utility scale energy storage in Colorado. Compressed air can use a salt cavern, aquifer, or a hard rock mine to store high pressure air. The research cites the existence of all three geological features in Colorado but concentrates on hard rock mines. It reports that Clear Creek Power, LLC, is developing a wind farm above Georgetown, Colorado, and is interested in the possibility of using the abandoned mine beneath their wind site for compressed air storage. There are other proposals pending in Logan County to store wind power. See Figure 6 below.

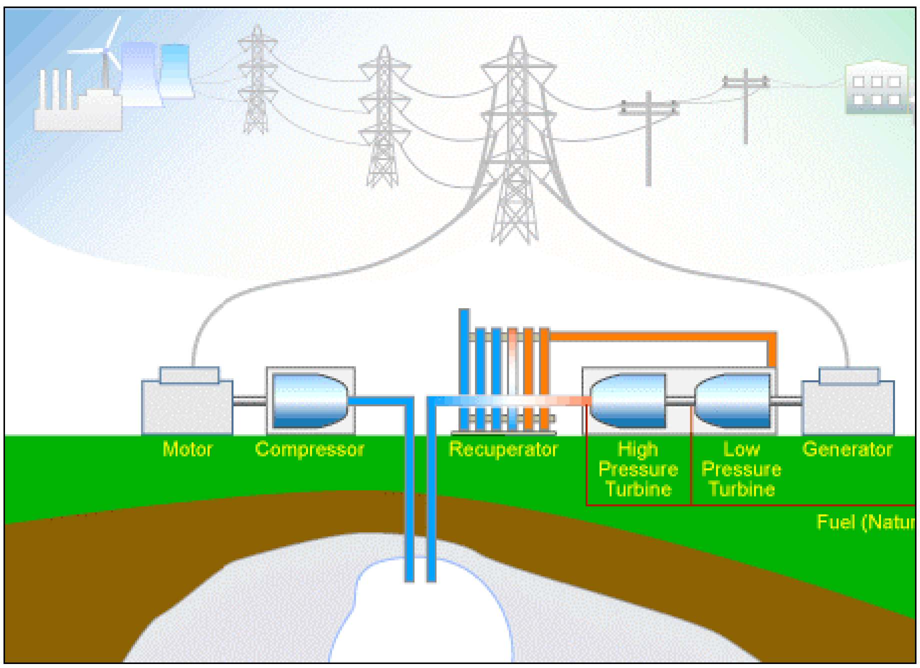


**Figure 6: Generic Compressed Air Energy Storage**

As mentioned earlier, there are site-specific data for each of three technologies and a list of references for readers to research the potential of energy storage in Colorado.

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## 6. Transmission System

The transmission network provides the vital link between electricity generation sources that produce electricity and the distribution systems that deliver electricity to the homes, businesses and industries that use it. As shown in Figure 7, electricity is generated at various generating sources and delivered to transmission substations for step up voltage for transmission through transmission lines for long distances until it reaches the load centers' substations for step down voltage for distribution through distribution systems to businesses and homes.

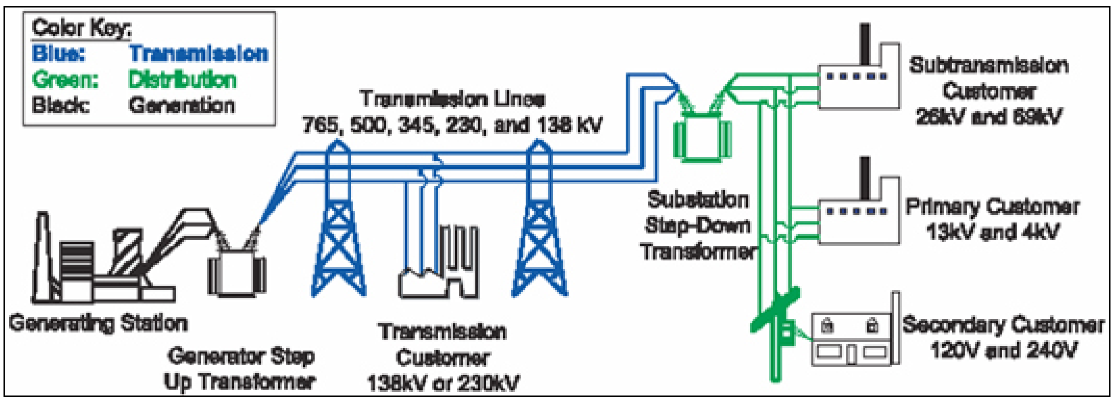


**Figure 7: Components of Electricity Industry**
Source: DOE

The principal function of high-voltage transmission lines is to transfer bulk power from generating plants at various locations to the load centers. The use of large generating units in conjunction with a transmission network allows utilities to economically dispatch power within their systems during normal conditions and allows the utilities to transfer power between regions during emergencies and shortages; this is considered an important function of high-voltage transmission lines when there are geographical imbalances in fuel and generation availability. The existence of transmission lines with adequate capacity between power systems makes it possible to have an integrated operation of the system

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with better performance and economic advantages.[7] High-voltage electric transmission lines serve several primary purposes: connecting generators to customers; increasing reliability; facilitating wholesale competition; and providing greater access to generation resources.

**7. Connecting Generators to Customers**

The principle function of high-voltage transmission lines is to connect remotely located generators to customers. Electricity transmitted at higher voltages can be moved greater distances with lower energy losses than with lower voltage infrastructure.

**Increasing Reliability**

Electric utilities interconnected with neighboring utilities through high-voltage transmission lines allow utilities access to neighboring utilities resources and receive power from neighbors in the case of generator outages and provide higher levels of reliable service to customers without bearing the cost of excess back-up generation.

**Facilitating Wholesale Competition**

High-voltage transmission line provides for utilities to engage in wholesale electric power trades. Wholesale transactions allow utilities to reduce power costs and increase power supply options. In 1996, the Federal Energy Regulatory Commission (FERC) issued its landmark Orders 888 and 889, which required utilities to allow non-utilities, or independent power producers, access to, and use of, utility transmission systems. FERC's orders changed the ways electricity production decisions are made and the transmission systems are used and operated. Since 1996, the transmission system has been slowly transformed into an interstate highway of commerce upon which emerging wholesale electricity markets depend.

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[7] EPRI. *Transmission Line Reference Book, 345 kV and Above, Second Edition*. 1987.

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**Providing Greater Access to Generation Resources**

In general, additional high-voltage transmission lines are needed to bring wind and coal-fired generation from remote locations to customers in high population areas such as Colorado’s Front Range. The more difficult it is to construct new transmission lines, the higher the likelihood that additional electricity will have to be generated near customers, likely fueled by natural gas. For example, Xcel Energy announced in December 2006 that it would not pursue some wind projects located in Eastern Colorado due to transmission constraints.

## 8. The U.S. bulk power system

The U.S. bulk power system has three major power grid networks, which include smaller groupings of power pools. These major networks consist of high-voltage transmission connections among individual utilities, designed to permit the transfer of electrical energy from one part of the network to another. The three networks or NERC Interconnections are Eastern Interconnected System (*Eastern Interconnection*) Western Interconnected System (*Western Interconnection*) Texas Interconnected System (*ERCOT Interconnection*). See Figure 8.

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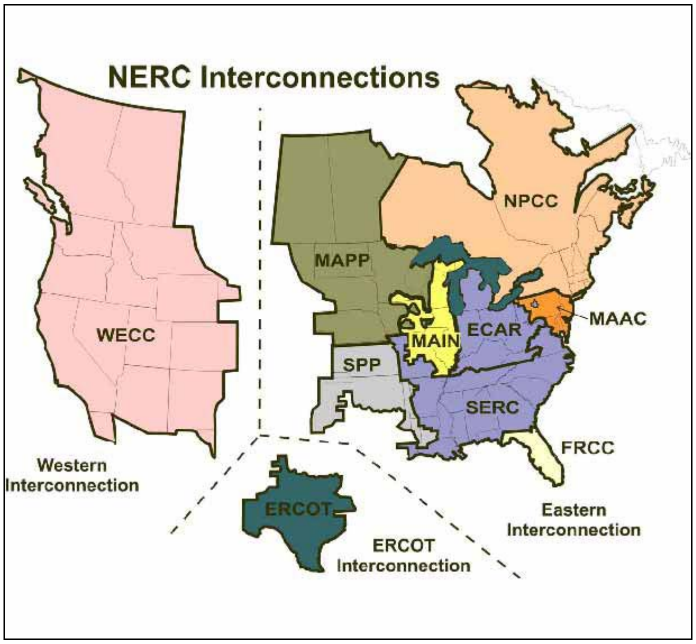


**Figure 8: U.S. Three Major Interconnections**

The three major networks are not interconnected with each other. Direct current ties bridge the electric separation between the grids by converting alternating current to direct current and then converting it back to alternating current.

U.S. utilities are interconnected with one other within these three major grids. The interconnected utilities within each power grid coordinate operations and buy and sell wholesale power to each other. Colorado utilities are located in the Western Grid (or Western Interconnect).

## 9. Colorado's Transmission System

Colorado is located in the Western Interconnection and utilities owning transmission facilities are members of the Western Electricity Coordinating Council

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(“WECC”).[8] The WECC is the Regional Entity for the Colorado transmission system, responsible for enforcement of North American Electric Reliability Corporation (NERC)[9] reliability standards related to transmission planning. The WECC does not offer transmission services under a regional Open Access Transmission Tariff (OATT), and there is presently no functioning Regional Transmission Organization (RTO) for the Colorado utilities transmission system.[10]

The transmission network of Colorado is located within the Rocky Mountain Region of the WECC. As shown in Figure 9 below, the transmission systems in Colorado is owned and operated by PSCo, Black Hills, Tri-State Generation and Transmission (TSG&T), Western Area Power Administration (WAPA), Colorado Springs Utilities (CSU), and Platte River Power Authority (PRPA). The electric system in Colorado is covered by two control areas or regions:[11] Colorado East (the Front Range) and Colorado West (west of the Continental Divide). Colorado East control area is operated by Xcel Energy (aka Public Service Company of Colorado, PSCo), and Colorado West control area is operated by WAPA.[12]

[8] Available at: http://www.wecc.biz/
[9] Available at: http://www.nerc.com/
[10] Transmission service is offered under OATT is reserved and/or scheduled capacity on transmission lines between specified Points or Receipt and Delivery.
[11] Control Area is referred to an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.
[12] Available at: http://www.wapa.gov/

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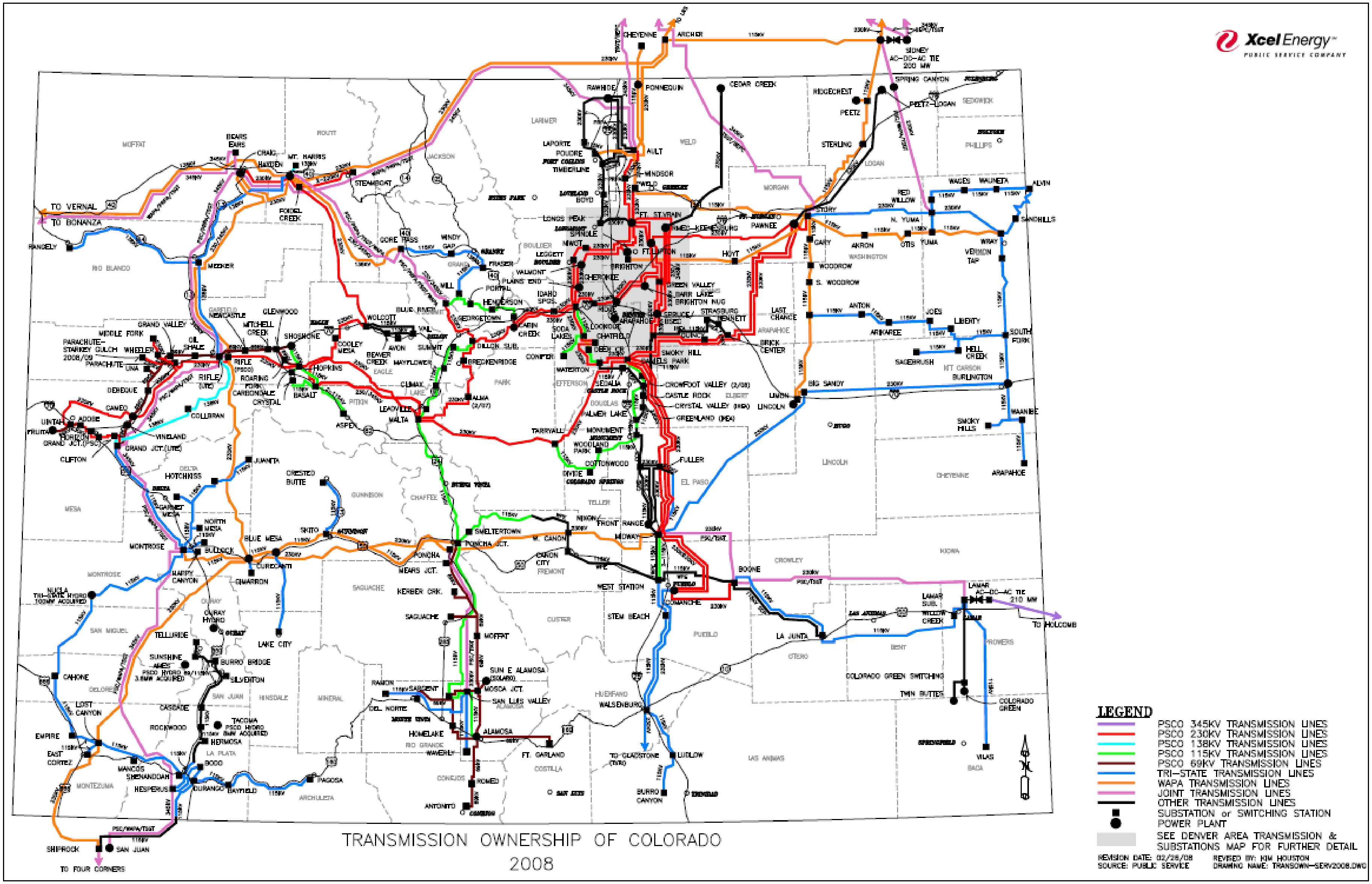


**Figure 9: Transmission Ownership of Colorado**

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Power flows into and out of Colorado are constrained by the carrying capacity of a set of transmissions lines. Power flow into Colorado from the north is constrained by transmission lines limits known as TOT-3 limits, from the southwest (Four Corners) by TOT-2A limits, and from the West by TOT-1A limits.[13] The transmission between two Colorado regions is constrained by TOT-5 limits. The transmission between Fort Collins and Denver is constrained by TOT-7. Figure 10 depicts Colorado's two control areas and major transmission constrained diagram.

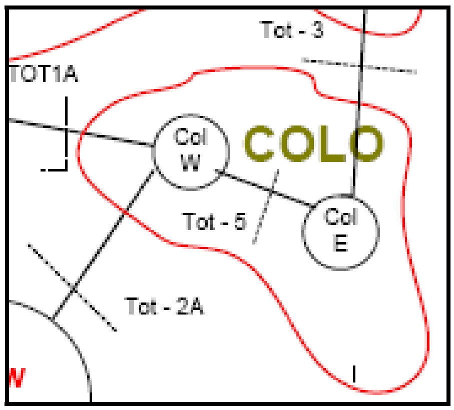


**Figure 10: Colorado Transmission Constrained Diagram**

Transmission studies show Colorado's high-voltage transmission capacity being fully utilized during periods of high demand. This is partly due to the fact that Colorado is located, like an island, on the Eastern boundary of the Western Interconnect. As explained above, due to location and TOT constraints, there is limited ability to gain transmission capability with the Eastern Grid, because access is limited to DC ties at Stegall and Sidney Nebraska, and Lamar, Colorado.[14] Likewise, there is limited transmission capability with New Mexico in the south and with Utah in the west. Finally, the TOT-3 high-voltage transmission constraints limit the movement of power from existing plants in Wyoming to Colorado.

Table 6 depicts the limits of the Colorado Transmission Constrained Paths.  Colorado does import and export power but in general is a net importer of power. The imports into Colorado are limited to TOT3 limits from north to south at TOT3 rating of 1,605 MW.

[13] The term "TOT" is short for Total transfer capability of a set of transmission lines over a geographically defined boundary.
[14] Colorado is located at the eastern edge of Western Interconnect, like an island with limited transmission capability with the Eastern Interconnect.

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**Table 6: Colorado Transmission Constrained Paths**

| PATH | PATH DESCRIPTION | RATING |
|---|---|---|
| TOT 1A | Utah to Western Colorado | E to W: 650 MW |
| TOT 2A | Four Corners to Southwest Colorado | N to S: 690 MW |
| TOT 3 | Wyoming to Northeast Colorado | N to S: 1,605 MW |
| TOT 5 | Western Colorado to Eastern Colorado | W to E: 1,675 MW |

Source: CCPG[15]

As mentioned earlier, Colorado is on the eastern edge of the Western Electric Interconnection, which operates asynchronously from the Eastern Electric Interconnection. Xcel Energy's new 345 kV transmission line from Holcomb, Kansas to Lamar, Colorado (known as Lamar Tie-Line) coupled with a 21 0 MW High Voltage Direct Current ("HVDC") back-to-back converter station provides the first link in Colorado between the two Interconnections.[16]

[15] Colorado Coordinated Planning Group for Transmission, http://ccpg.basinelectric.com/

[16] The Tie-Line, owned by Xcel Energy, has been in-service since December 3 1, 2004. The Lamar DC converter became the seventh DC tie between the Eastern and Western Grids in the United States. The other six DC ties are located at Miles City, Montana; Rapid City, South Dakota; Stegall, Nebraska; Sidney, Nebraska; Blackwater, New Mexico; and Artesia, New Mexico.

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## 10. Colorado Existing High Voltage Transmission System Ownership

**Public Service of Colorado (PSCo)**

PSCo is a vertically integrated utility that owns and operates transmission facilities in the state of Colorado. PSCo owns and maintains approximately 4,000 circuit-miles of transmission lines 115kV and above. PSCo's transmission lines are rated 69 kV, 115 kV, 230 kV, and 345 kV. PSCo is the transmission provider for the PSCo transmission system. PSCo has ownership in the jointly owned western slope transmission facilities extending from the Craig/Hayden area in Northwestern Colorado south to the Four Corners area. PSCo uses 49 transmission substations and 141 distribution substations to deliver electric energy.

**PSCo's Available Transmission for Generation Interconnection**

Recent transmission studies performed by PSCo in response to requests under the Large Generator Interconnection Agent (LGIA) process summarize the capacity of existing transmission system which can accommodate potential new generation at 1,150 MW. The results of these transmission studies are posted on PSCo's Open Access Same-Time Information System (OASIS) web-site for potential bidders and the interested parties.[17] Studies performed under the LGIA process indicate the cost of the interconnection as well as the schedule needed to interconnect a facility to the transmission system. PSCo also reports that it normally takes 18 months to add a generation interconnection to its transmission facilities following the authorization to proceed with construction. The results of the studies are summarized in Table 7 followed with a short description of each project.

[17] See http://www.rmao.com/wtpp/PSCO_Studies.html

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**Table 7: Summary of Available Transmission at Generation Locations**

| Location | Generation | Timing |
|---|---|---|
| Pawnee 230 kV | 25 MW | 18 months for a new Interconnection |
| Missile Site 230 kV | 250 MW | December 2010 |
| Keensburg 230 kV | 250 MW | 18 months |
| Jackson Fuller 230 kV | 200 MW | 18 months |
| San Luis Valley 230/115 kV | 125 MW | 18 months |
| Comanche 345 kV | 300 MW | 18 months |
| **TOTAL w/o Pawnee** | **1,150 MW** | |
| Pawnee 345 kV | 500 MW | June 2013 (part of SB07-100) CPCN |
| **TOTAL w/ Pawnee** | **1,650 MW** | |

Estimated existing transmission available for generation interconnection at the facility locations shown in Table 7 are reported by PSCo based on stand-alone technical studies developed through the FERC LGIA process. Pawnee – Smoky Hill 345 kV transmission line is part of SB07-100 projects discussed in the next section of this report. Descriptions of substation locations listed in Table 7 are as follows:

**Ault Substation 230 kV –** A transmission study at the Ault substation located in northern Colorado indicates that the substation, on a stand-alone, can accommodate no generation interconnection (0 MW) during normal transmission operating conditions (Ref. System Impact Study GI-2007-3 on the OASIS). What this means is, currently there is no transmission capability to transmit additional resources over the existing transmission system.

**Comanche Substation 345 kV –**A transmission study at the Comanche substation located near Pueblo indicates that the substation, on a stand-alone, can accommodate approximately 300 MW of generation interconnection during normal transmission operating conditions (Ref. System Impact Study GI-2007-2 on the OASIS), at an interconnection cost of $3.4 million and a construction schedule of 18 months. It is reported that several other projects have to be completed prior to accommodation of 300 MW at Comanche. The projects are reported as; 1) Midway to Waterton 345 kV project, 2) the second Reader to Comanche 115 kV line, and 3) replacement of the 230/115 kV with larger auto transformers at Comanche.

**Jackson Fuller 230 kV –** A transmission study at the Jackson Fuller substation located south of Denver indicates that the substation, on a stand-alone, can accommodate approximately 200 MW of generation interconnection during normal transmission operating conditions (Ref. System

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Impact Study GI-2007-10 on the OASIS), at an interconnection cost of $4.0 million and a construction schedule of 18 months.

**Keensburg 230kV – A** transmission study at the Keensburg substation located west of Brush and Rocky Mountain Energy Center indicates that the substation, on a stand-alone, can accommodate approximately 250 MW of generation interconnection during normal transmission operating conditions (Ref. System Impact Study GI-2007-6 on the OASIS), at an interconnection cost of $2.23 million and a construction schedule of 18 months.

**Lamar Substation 230 kV –** A transmission study at the Lamar substation located in Lamar indicates that the substation, on a stand-alone, can accommodate no generation interconnection (0 MW) during normal transmission operating conditions (Ref. System Impact Study GI-2007-5 on the OASIS). What this means is, currently there is no transmission capability to transmit additional resources from the wind rich Energy Resource Zone (ERZ) 3 to the Front Range unless more transmission infrastructures is planned and constructed to connect southeast Colorado to load.

**Missile Site 230 kV –** A transmission study at the Missile Site substation located in east of Denver indicates that the substation, on a stand-alone, can accommodate approximately 250 MW of generation interconnection during normal transmission operating conditions (Ref. System Impact Study GI-2007-13 on the OASIS), at an interconnection cost of $4.6 million and a construction of switching station will be completed by 2010.

**Pawnee Substation 230 kV –** A transmission study at the Pawnee substation located in Brush indicates that the substation, on a stand-alone, can accommodate approximately 25 MW of generation interconnection during normal transmission operating conditions (Ref. System Impact Study GI-2007-2 on the OASIS), no interconnection cost is estimated but construction schedule is estimated to be 18 months. It is also reported that additional generation could be added if the existing coal, gas and wind generation is re-dispatched. However, the combined total of generation resources in the Pawnee area, prior to the construction of additional transmission

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facilities, is limited to total resources currently in service with an additional 150 MW of wind project scheduled to be online by 2009.

**San Luis Valley 230 kV/115 kV –** A transmission study at the San Luis substation located in San Luis Valley indicates that the substation at 230 kV or 115 kV, on a stand-alone and prior to any new SB07-100 projects being developed, can accommodate approximately 125 MW of generation interconnection during normal transmission operating conditions (PSCo performed the study under internal planning studies, not posted on the OASIS), with no interconnection cost estimated at this time, and construction schedule estimated to be around 18-24 months. This facility is jointly owned by Tri-State which would be responsible for the design and construction of the facility.

As a result of recent legislative initiatives (i.e., HB06-1325, SB07-91, and SB07-100) and the PUC Electric Resource Planning requirements, PSCo has begun implementing a number of transmission projects identified as needed to complete the resource planning process. The transmission projects that are under consideration and implementation are:

**Midway-Wateron 345 kV Project –** This project was approved by the PUC and issued a Certificate of Public Convenience and Necessity (CPCN) based on the need to interconnect a 500 MW Independent Power Producer (IPP) facility which later was terminated. PSCO has to reapply and justify the need for this project in light of cancellation of the IPP facility. PSCo has reported that it is in the process of reapplying with an emphasis that the project is needed to meet the requirements of the SB07-100 projects from ERZ 3, 4, and 5 with an in-service date of June 2011.

**Pawnee-Smoky Hill 345 kV –** This project was approved by the PUC and issued a CPCN for the construction of a 95 mile long transmission expansion with an in-service date of June 2013. A transmission study indicates that the Pawnee substation, on a stand-alone, can accommodate approximately 500 MW of generation interconnection during normal transmission operating conditions (Reference study in the PUC Docket No. 07A-421E).

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The above transmission studies were all based on PSCo's load forecast, as of December 2008, which called for 2,365 MW of new generation to be developed by independent power producers before 2015, with 800 MW being earmarked for wind, up to 225 MW for concentrating solar power and the rest, 1,340 MW for natural-gas powered generation facilities (see earlier Table 3 for PSCo's Preferred Plan). On March 20, 2009 PSCo announced that due to economic downturns its load forecast has changed downward and it will only need 1800 MW of new generation (i.e., 24% less than December 2008 forecasted need) which wind and gas need to compete for 1,600 MW, with the remaining 200 MW earmarked for concentrating solar power.

Public Service's recent filling with the PUC provides transmission information available on the OATT website and the timing of proposed new transmission construction under the SB07-100 for bidders as to where they should place their facilities to maximize selection of their bids.[18] PSCo also emphasizes that it cannot guarantee that any specific generation portfolio can be accommodated without conducting power flow, stability, and other reliability and OATT-required studies that include the specifics of any proposed new generation.

[18] See PSCo filling with the PUC on March 13, 2009 in Docket No. 07A-447E that summarizes the transmission information that is currently available on PSCo's Open Access Transmission Tariff (OATT) website.

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## 11. Senate Bill 07-100

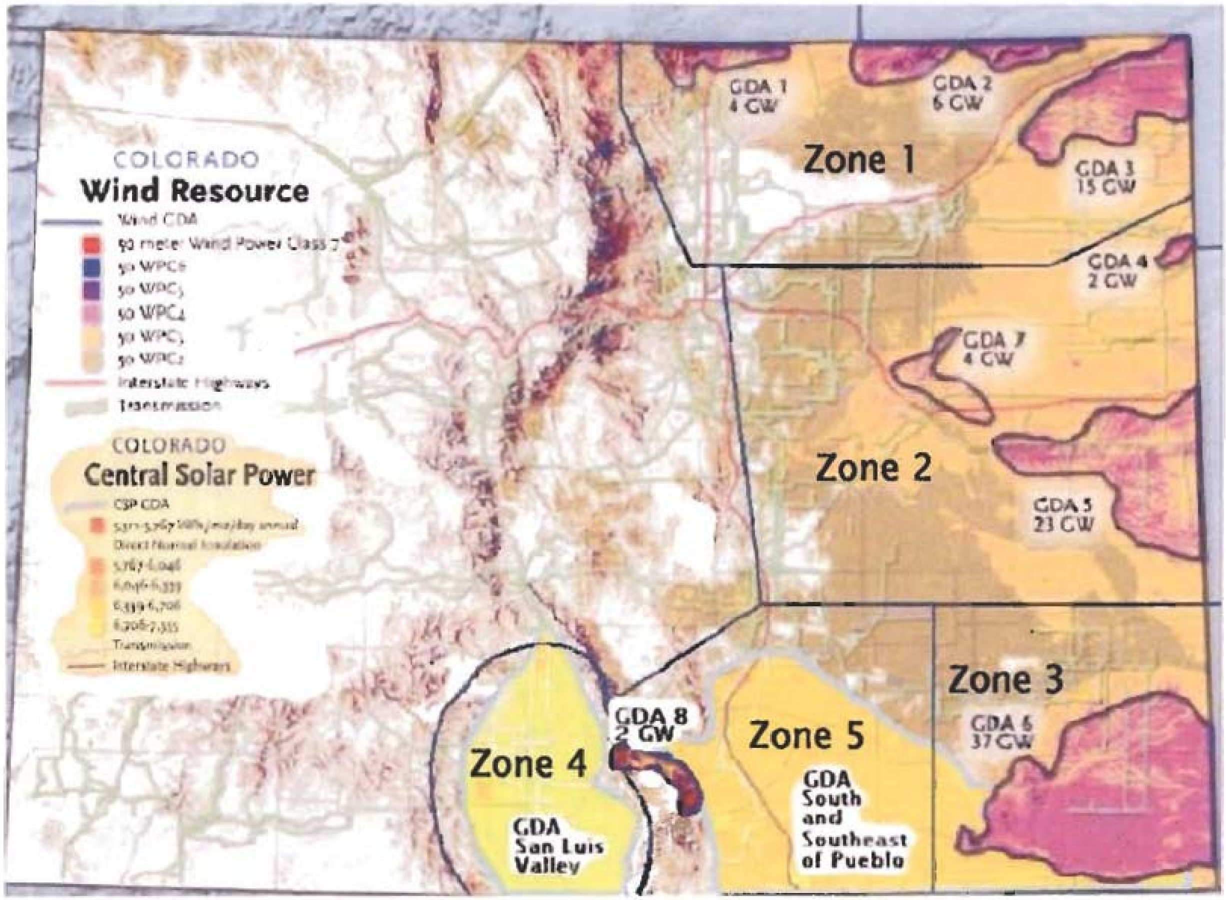
Colorado's Sixty Sixth General Assembly passed Senate Bill 07-100 (SB07-100) upon the recommendation of the 2006 Transmission Task Force on Reliable Electricity Infrastructure, which reported "Colorado's ability to ensure the continued supply of affordable, reliable electricity and to build a vibrant economy depends on sufficient transmission capability." The Task Force report also indicated that "[t]oday the system is strained and, if current trends continue, there will not be adequate transmission to meet the needs." SB07-100 requires rate-regulated electric utilities, such as PSCo, on or before October 31 of each odd-numbered year, to do the following:

a) Designate Energy Resource Zones ( "ERZs");
b) Develop plans for the construction or expansion of transmission facilities necessary to deliver electric power consistent with the timing of the development of beneficial energy resources located in or near such zones;
c) Consider how transmission can be provided to encourage local ownership of renewable energy facilities, whether through renewable energy cooperatives as provided in section 7-56-210, C.R.S., or otherwise; and
d) Submit proposed plans, designations, and applications for certificates of public convenience and necessity to the Commission for simultaneous review.

ERZs are defined as "a geographic area in which transmission constraints hinder the delivery of electricity to Colorado consumers, the development of new electric generation facilities to serve Colorado consumers, or both." PSCo has identified five geographic zones, considering both electric transmission constraints as well as the locations, where significant renewable generation potential for wind and solar exist, of new electric generation resources that are most likely to be developed.

In the 2008 Report, PSCo identified and added the fifth ERZs to the four ERZs indentified and reported previously in the State of Colorado. Three of the ERZs are in eastern Colorado and two in southern Colorado. Figure 11 shows the five ERZs superimposed on the wind and solar GDAs that were indentified in the SB07-91 Task Force Report. The new ERZ 5 places the Boone, Walsenburg, and Comanche area interconnections into their own zone.

**Figure 11: Colorado Five Energy Resource Zones with GDAs**




## Senate Bill 07-100 Proposed Transmission Projects

PSCo filed its first SB07-100 report with the PUC on October 31, 2007 outlining expected activities to undertake in response to the requirements of SB07-100. Subsequent reports provided updates on the identification of ERZs and description of transmission plans prepared pursuant to SB07-100.[19] Prior to developing the transmission plans, the designation of ERZs were reviewed to ensure all of the Generation Development Areas (GDAs) identified in the Senate Bill 07-91 Task Force Report[20] were included within the proposed ERZs to plan transmission infrastructure that provide adequate transfer capability for transfer of generation from ERZs to the load center, i.e., the Front Range.

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[19] Reports are available online at: http://www.rmao.com/wtpp/SB100.html

[20] SB 07-091 established a task force to identify renewable resource Generation Development Areas within Colorado that have potential to support the development of renewable resources. The SB 07-091 Task force issued its report entitled "Connecting Colorado's Renewable Resources to the Market" on December 31, 2007. The report is available at: www.colorado.gov/energy .

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**Table 8: PSCo's Proposed Transmission Projects Under SB07-100**

| Project | Description | Generation Injection | Tentative In-Service Date | Energy Zone |
|---|---|---|---|---|
| Pawnee-Daniels Park 345 kV Line | Second circuit 345 kV line in Energy Resource Zone (ERZ) 1 | 300-500 MW | 2016 | 1 |
| Ault – Cherokee 230 kV Line | New 230 kV line in ERZ 1 | 300-600 MW | 2015 | 1 |
| Missile Site | 345/230 kV switching station on the Pawnee – Daniels Park line in ERZ 2 | 200-500 MW | 2010 (230 kV)<br>2013 (345 kV) | |
| Lamar – Comanche and Lamar – Missile Site 345 kV Lines | New 345 kV lines to access ERZ3 | 800-1000 MW | 2016 | 3 |
| Lamar – Vilas 345 kV Line | New 345 kV line in ERZ3 to access wind rich area | | 2016 | 3 |
| San Luis – Calumet – Comanche Line | Double circuit 230 kV line (SLV to Calumet) and double circuit 345 kV line (Calumet to Comanche) | 600–1000 MW | 2013 | 4&5 |
| Midway – Waterton 345 kV Line | Needed for system reliability and utilization resources in ERZ 3, 4 and 5. Must file modification to CPCN received 9/07 in order to construct | ---- | 2011 | 3, 4, & 5 |
| Pawnee – Smoky Hill 345 kV Line | 345 kV line from Pawnee to the Denver load center. CPCN received in 01/2009 | 500 MW | 2013 | 1 |
| | **RANGE** | **2700 - 4100** | **2010-2016** | **1,3,4& 5** |
| Generation values are based on stand alone (not simultaneous) studies | | | | |

Source: Docket No. 07A-447E, PSCo filing with the PUC on March 13, 2009.

Table 8 shows the proposed transmission projects under SB07-100 with description of the projects and the range of generation injections with tentative in-service date and the related energy zones. It should be noted that the range of generation injection is based on stand alone study of each transmission project. At this time, there is no one study that incorporates all projects simultaneously to estimate the increased transmission capability in total. The cumulative range shown in Table 8 is for illustrative purposes. The detail description of each project is given below:

**Ault-Cherokee 230 kV Line -** This project includes a 230 kV transmission line from the Ault Substation to the Cherokee Substation at 85 miles which will consist of 59 miles single circuit line from Ault to Ft. Lupton and 26 miles double circuit line rebuilding the existing 115 kV line from Ft. Lupton to the Cherokee operating on one side at 115 kV for Tri-State load and the other side will be operated at 230 kV to complete the Ault-Cherokee 230 kV circuit. This project is

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designed with line capability of 300-600 MW in response to SB07-100 to transport generation interconnection from ERZ 1 with the earliest in-service date of 2015.

**Lamar-Comanche and Lamar-Missile Site 345 kV Lines –** This large project includes two new 345 kV transmission lines from Lamar to Missile Site, 210 miles, and from Lamar to Comanche at a distance of approximately 120 miles. These two lines, with transfer capability of 800-1000 MW, are designed in response to SB07-100 to transport wind generation from ERZ 3, Baca County to Denver with the earliest in-service date of 2016.

A re-evaluation of this project at double circuit 345 kV lines will increase the transfer capability from 800-1000 MW to 1500-2000 MW from ERZ 3. A joint ownership by Tri-State for the second circuit from Lamar to Comanche could provide shared risk and benefits for joint owners.

**Lamar-Vilas 345 kV Line -** This project includes a 230/345 kV transmission line from Lamar substation to Vilas substation, 57 miles, designed in response to SB07-100 to transport wind generation also from ERZ 3, Baca County to Denver with the earliest in-service date of 2016.

**Pawnee-Daniels Park 345 kV Line -** This project includes a 345 kV transmission line from Pawnee Substation to the Daniels Park Substation, which also will result in a new Smoky Hill to Daniels Park 345 kV line, designed in response to SB07-100 to transport potential generation from ERZ 1 and 2. The line is expected to accommodate approximately 300-500 MW of generation interconnection at or near the Pawnee Substation and/or Missile Site Substation with an in-service date of 2016.

**San Luis-Calumet-Comanche Line -** This project includes two lines, a double-circuit 230 kV transmission line from San Luis Valley Substation to a new Calumet Substation, near Walsenburg, and a second line, a double-circuit 345 kV transmission line from Calumet to the Comanche Substation. This project is designed in response to SB07-100 to transport potential generation from ERZ 4 and 5. The project is expected to accommodate approximately 800-1000

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MW of generation interconnection at or near the San Luis Valley Substation and/or the Calumet Substation with an in-service date of 2013.[21]

A re-evaluation of the proposed line from San Luis Valley Substation to Calumet Substation with a double-circuit 345 kV may warrant much more benefits than an incremental cost of about $30 million dollars. A double circuit 345 kV transmission line could increase the capacity of the project from 600-1000 MW to 1000 – 1500 MW for solar generation potential in ERZ 4 and 5. In the early years the lines may be underutilized but, as more renewable energy resources are developed in ERZ 4 and 5, the lines will reach their maximum operating limits.

As noted before, all of the transmission studies were conducted under the stand-alone condition for new generation interconnection location. No cluster studies were performed to evaluate the impact of all new generation added together to the transmission system. As reported by PSCo, the in service dates of any or all of these new lines could be affected once the cluster studies are conducted. Figure 12 shows the proposed transmission lines routing under the SB07-100 process.

[21] In April 2009, PSCo and Tri-State filed a CPCN application for the San Luis-Calumet-Comanche Line with the Public Utilities Commission.

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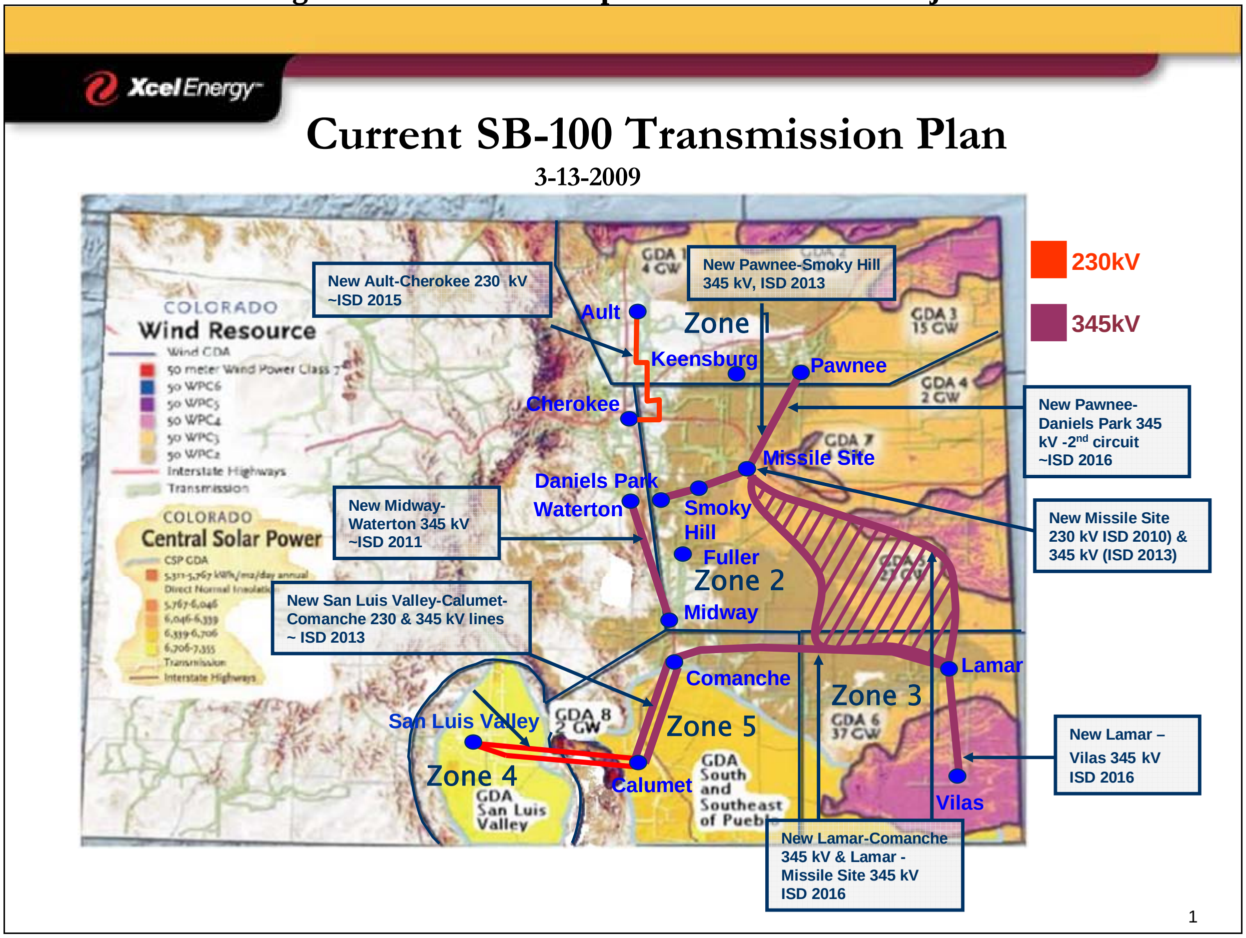
**Figure 12: SB07-100 Proposed Transmission Projects**




It should be noted that the completion of these projects with the expected in-service dates are highly dependent on timely approval by the PUC of a CPCN application, siting and permitting, combined with construction and material delivery schedules.

It should also be emphasized that while PSCo has proposed and is considering the above transmission expansion plans, it is not certain how many of them will be approved and implemented and in what order. As reported by PSCo in its 2008 SB07-100 update, a number of factors enter into the decision whether to go forward with a transmission project, including generation resource availability, community and local government concerns, cost, capital funding requirements, comparison with alternative resources, regulatory approval, and neighboring utility participation. Before spending more time to conduct studies and prepare for CPCN filing, PSCo has proposed a prioritization schedule to the PUC by ranking the proposed projects as “High”, “Medium”, or “Low”. A project has a High priority ranking if it is

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establishing backbone transmission into REZs except REZ 1 because the Pawnee – Smoky Hill Project is already underway which will diminish constraints in REZ 1.[22] A project is given a Low priority ranking if it is considered a feeder line into the bulk transmission network. Table 9 lists the name of the projects, the REZs that they would serve, the priority of the project and the ranking within the priority showing the degree of importance. A numerical rank of "1" would mean the highest within the listed priority.[23]

**Table 9: Summary of Proposed Transmission Projects with Priority Ranking**

| Project | Zone Served | Priority & Rank |
|---|---|---|
| Pawnee-Daniels Park 345 kV | 1 | Med -1 |
| Ault-Cherokee 230 kV | 1 | Med – 2 |
| Missile Site Substation | 2 | High -2 |
| Lamar-Front Range:<br>a) Lamar-Comanche 345 kV<br>b) Lamar-Missile Site 345/500 kV | 3 | High -3 |
| Lamar-Vilas 230/345 kV | 3 | Low |
| Lamar-Front Range:<br>a) San Luis Valley-Calumet 230 kV<br>b) Calumet-Comanche 345 kV | 4, 5 | High -1 |

The evaluation of transmission costs when considering resources with one another is an evolving issue within the utilities and the PUC.[24] The Commission's recently established Transmission Investigatory Docket is investigating the transmission issues in Colorado and is expected to establish the ground rules for resource acquisition while considering transmission interconnection.[25] One of the topics that needs to be addressed, and is very important to utilities such as PSCo, is the Commission decision on ensuring that the transmission lines built under SB07-100 is built to the right places, e.g., ERZs and Generation Development Areas (GDAs)[26],

[22] Backbone transmission is referred to major transmission lines that strengthening region's bulk transmission network.
[23] See PSCo's SB07-100 Informational Report, November 24, 2008.
[24] Utilities generally prefer to minimize the cost of their resource portfolio, to the extent possible, by inviting the potential bidders into resource planning process to consider building resources where there are existing transmission lines with available transfer capability to avoid additional investment to upgrade or build new transmission lines. This approach limits the bidders' abilities to use the most promising REZs for renewable energy development.
[25] See Colorado PUC Docket No. 08I-277E
[26] A Generation Development Area (GDA) is a concentration of renewable resources within a specific geographic sub-region in Colorado that provides a minimum of one gigawatt of developable electric generating capacity that could connect to an existing or new high-voltage transmission line. See SB07-91 Report at: www.colorado.gov/energy.

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and helps encourage independent power producers to develop renewable energy generation resources in the already identified GDAs under competitive resource acquisition process at the right prices.

## 12. Tri-State's Transmission Projects

Tri-State owns wholly or jointly 5200 miles of transmission line across Colorado, Nebraska, New Mexico and Wyoming. Tri-State has indentified the need for more transmission as it posts on its website; "… the West's vast power supply network is currently strained – improvements and expansion to the system are essential to enhancing regional power reliability."

Tri-State Generation & Transmission Association received approval from the PUC for and built a 230 kV line from Walsenburg, Colorado to Gladstone, New Mexico. The line was placed in service on February 1, 2007. These and a variety of other projects have been, or are being, built in order to increase reliability within Colorado. Tri-State is working with its member system and is proposing a number of immediate upgrades to its transmission infrastructures across Colorado. The following is a list of key transmission construction projects posted on the Tri-State transmission website.[27]

[27] The link to Tri-State's transmission website is available at: http://www.tristategt.org/Transmission/

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## Tri-State's key transmission construction projects

**East Montrose Electric System Improvement Project** - Tri-State working with its member system, Delta-Montrose Electric Association, is proposing a new 18-mile, 115 kilovolt transmission line into the east side of Montrose, Colorado. Once completed, the East Montrose Electric System Improvement Project will strengthen the area's electrical system.

The proposed project is intended to bring numerous benefits to the area such as:

- boost load serving capacity to the area
- improve reliability of the existing electric delivery
- ultimately provide more dependable looped transmission service

**Poudre Valley REA power reliability improvement (Richard Lake to Waverly 115-kilovolt transmission line) -** Tri-State is proposing to construct a new 8-mile, 115-kilovolt transmission line to improve reliable electric service to the member-consumers of Poudre Valley REA. This line will provide the power delivery infrastructure needed to increase reliability and capacity of the existing transmission system. The new line would connect the Richard Lake Substation located west of the Anheuser-Busch brewery plant and the Waverly Substation near Douglas Lake on County Road 60. While various alternative routes have been examined, it was determined by Tri-State and Poudre Valley REA that this is the best route with the least amount of impacts to area residents and businesses.

**San Luis Valley Electric System Improvement Project** - Tri-State is proposing a new project in southern Colorado that would involve the construction of a double-circuit 230-kilovolt transmission line between electrical substations near the towns of Walsenburg and Mosca. This line will provide the power delivery infrastructure to increase the reliability and capacity of the existing transmission system and support proposed renewable energy development in the area. Xcel Energy will also partner with Tri-State in the project based on capacity requirements in the area and anticipated development of renewable resources.

**The Eastern Plains Transmission Project (EPTP) -** Tri-State has proposed a high-voltage transmission system across eastern and southern Colorado. The EPTP will assist Tri-State to serve the long-term needs of its member systems, enhance power delivery system reliability in

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the region, relieve existing constraints and provide opportunities for additional interconnections, including those from renewable energy projects. The future of the EPTP is unknown as this time until the status of the Holcomb Power Plant in Kansas is determined. An agreement has been reached with Sunflower Electric and the Governor, and the Kansas legislature has approved the agreement. However, other uncertainties and hurdles remain before a line to the Holcomb plant will necessarily be a part of Tri-State's plans.

The EPTP was part of the Colorado Long Range Transmission Planning Group (CLRTPG) 2015 transmission planning study. The CLRTPG recent study eliminated portions of the EPTP elements from the 2008-2018 study. Tri-State and other regional utilities and transmission providers participate in the CLRTPG, which provides a forum for electric load-serving entities in the region to jointly explore the potential for the development of a coordinated transmission network. Tri-State is also evaluating its members' needs, and with other utilities, is evaluating regional system requirements that could change the scope of EPTP.

Tri-State and Xcel Energy jointly pursue transmission projects in southern Colorado under a Memorandum of Understanding (MOU) recently signed between the two utilities. The projects identified in the agreement would strengthen southern Colorado's power delivery infrastructure, serve growing electricity needs and provide for the interconnection of new energy resources

As it stands today, Tri-State has stated that its transmission lines are at their capacity with no additional capacity available for interconnection. In the course of stakeholders' interview for this report, one stakeholder suggested better management of transmission system may offer additional transfer capability under the existing circumstances. For example, Tri-State owns two diesel-fired combustion turbines with 120 MW of rated capacity in Burlington Colorado and operates the turbines on emergency basis a few hours a year. Renewable energy developers are interested in entering into a firm but contingent transmission service contract with Tri-State to use the 120 MW reserved capacity on transmission lines for Burlington turbines which only may need to use the transmission lines a few hours a year. The contingent firm transmission service contract will give the right to Tri-State to drop the developer's resources when it needs to operate

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Burlington turbines for emergency or other use. This way of managing transmission system will free up some transfer capability on the existing transmission system. Today, there is no oversight or regulatory mechanism in place to facilitate such an efficient operation and management of existing transmission system in Colorado.

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## 13. Western Area Power Administration Rocky Mountain Regions

Western Area Power Administration (WAPA) is one of the largest transmission owners in the country. WAPA owns about 34.5% of all government lines and less than 1% of all lines in the U.S. The average age of all WAPA lines is 44 years. The average loss on WAPA lines is currently about 4%. WAPA's Rocky Mountain Region, based in Loveland, Colorado, operates and maintains WAPA's transmission facilities in Colorado, Wyoming, and Nebraska, which were constructed to market and deliver power from the Loveland Area Projects.[28] The region also markets the northern portion of the Salt Lake City Area/Integrated Projects transmission system in Colorado, Wyoming and Utah. The region manages a Control Area in Loveland, Colorado, known as the Western Area Colorado Missouri (WACM). WAPA markets available transmission capacity on the WACM OASIS site.[29]

WAPA recently announced near-term potential projects for its Colorado transmission system to be completed by 2011. Table 10 shows WAPA's near-term rebuild and construction projects in Colorado with budgeted amount.

**Table 10: WAPA's Near-Term Transmission Projects in Colorado**

| WAPA Potential Infrastructure Projects – (thousand dollars) | 2009 | 2010 | 2011 |
|---|---|---|---|
| Rebuild Erie-Hoyt 115-kV T-line - CoSponsor (46mi)(1952) | 5,000 | 2,000 | |
| Construct 230-kV addition to Beaver Creek Substation | 6,250 | | |
| Construct 230-kV addition to Ault Substation for new 230-kV line | 1,170 | | |
| Ault Substation 230/115-kV additions - CoSponsor (230/115 xfmr; 2-230-kV PCB; 2-115-kV PCB) | 500 | 500 | |
| Granby-Windy Gap 69-kV rebuild - CoSponsor (12mi)(1939) | 1,500 | 1,250 | |
| Lovell-Yellowtail #1& #2 115-kV rebuilds - Phase 1&2 (NPS) (15mi ea)(#1 1956)(#2 1966) | 750 | 40,000 | 2,225 |
| Central Wyoming Transmission Improvements (186mi) (6 lines - 1949-1952) | 5,000 | 60,000 | 2,000 |
| Weld 230/115-kV Transformer Addition | | 3,500 | 1,500 |
| Install 15MVAR shunt capacitor bank at Ft. Morgan West Substation | | 750 | |
| Rebuild Flatiron-Weld at 230-kV double circuit (30mi) | 500 | 27,000 | 2,500 |

WAPA, the Wyoming Infrastructure Authority, and TransElect signed an MOU in September, 2005 to begin development of Wyoming-Colorado Intertie (TOT3) partnership project. WAPA plays the advisory role in WCI Project. WAPA has not contributed any financial support, just manpower to the Project development. Recently published WAPA's Federal

[28] Available at: http://www.wapa.gov/rm/default.htm
[29] Avaiable at: https://www.oatioasis.com/cwo_default_WACM.html

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Register Notice under the American Recovery and Reinvestment Act for potential access to the $3.25 billion in borrowing authority from the Treasury for funding renewable-based transmission projects may benefit the WCI Project which is in Phase II of the WECC Three-Phase Rating Process. The WCI Project is discussed in next section.

The Mount Elbert hydroelectric pumped-storage facility in Colorado is operated by WAPA as a baseload resource, which is a potential balancing resource in Colorado. The prospect of using neighboring resources and moving toward a larger balancing authority, beyond the PSCo system,[30] is a key to more wind penetration in Colorado even with current transmission and operational limitations. In order to move Colorado to a larger authority and make it operational it would have to include WAPA's control area and resources. According to WAPA, at this time, Mt. Elbert is used quit often for Automatic Generation Control (AGC). It is a Loveland Area Project customer resource and any proposed change in its disposition would require a formal public hearing. The next formal public hearing is scheduled for 2024. WAPA is analyzing Balancing Authority (BA) consolidation among its BAs, however, not with PSCo.

Along the same line, we discussed Scheduling and Imbalance Charges with WAPA. One of the steps utilities, in particular PSCo, could take to reduce wind integration costs is to "institute sub-hourly schedules" with independent power producers to increase response capability on the PSCo's system. WAPA has shown interest in experimenting it within WestConnect and WAPA is discussing the possibility with stakeholders and participants.

We also discussed with WAPA the possibility of implementing and sharing Area Control Error (ACE) in Colorado. Sharing ACE diversity through increased cooperation with other utilities provide flexibility for more wind penetration. ACE sharing has been established in other parts of the country. WAPA indicated that it is planning on joining several other WestConnect participants in the ACE Diversity Interchanged (ADI) experiment which shares regulation (AGC) among SCADA[31] computer within the WECC.  ADI increases efficiency and lowers

[30] PSCo operates Cabin Creek hydroelectric pumped-storage (324 MW) facility in peak hours on as needed basis but more often uses the facility to meet its operating reserve and to maintain compliance with NERC's Control Performance Standards.
[31] SCADA stands for *Supervisory Control And Data Acquisition* which is a computer system monitoring and controlling electrical power transmission and distribution systems.

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operational costs when communications between control areas takes place.[32] Participants within Northern Tier Transmission Group (NTTG) are coordinating some aspects of their load balancing through ADI which is the first example of how enhanced cooperation between key control areas can deliver improved efficiencies at low cost.

[32] ADI is the pooling of Area Control Errors (ACE) to take advantage of control error diversity (momentary imbalances of generation and load). The ADI pilot project has been developed by British Columbia Transmission Corporation (the Host) and the four control areas (Participants) operated by Idaho Power Company, NorthWestern Energy and PacifiCorp (Eastern and Western control areas). See ADI discussions at NTTG web site available at : http://nttg.biz/site/index.php?option=com_content&task=view&id=14&Itemid=83

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## 14. Colorado Interstate Transmission Projects Underdevelopment

**Wyoming – Colorado Intertie Transmission Project**

As discussed earlier, the Wyoming-Colorado lntertie ("WCI") is a proposed 345kV transmission line intended to bring new generation from southeastern Wyoming to the Pawnee Substation in northeast Colorado. Wyoming-Colorado (TOT 3) Intertie Project is a *partnership* with Wyoming Infrastructure Authority (WIA) and WAPA:

- Project Participants– WIA, WAPA & Trans-Elect
- Recommended by Rocky Mountain Area Transmission Study (2004)
- Access to Wyoming & Colorado Wind
- 180 mile 345 kV line integrated line from Larimer River Station (LRS) to Pawnee
- Capacity: ~900 MW
- 2008 Open Season capacity auction completed
- On-line after 2011
- Delivery to Pawnee where PSCO plans 1,000 MW injection point for ERZ 1

Currently, the project sponsors are completing a second round open season to auction the capacity of the project to interested bidders. The WCI provides the necessary transmission line for wind energy developers in Wyoming to develop wind farms and import across the WCI facility and sell the output to utilities in Colorado. The WIA was created in 2004 with the goal of diversifying and growing that state's economy through the development of its electric transmission infrastructure. The WIA is responsible for planning, financing, building, maintaining and operating the electric transmission system and its related facilities. The WIA is authorized to: issue up to $1 billion in bonds to finance new transmission lines to support new generation facilities in the state; own and operate lines in instances where private investment is not offered; enter into partnerships with public or private entities to build and upgrade transmission lines; investigate, plan, prioritize and establish corridors for electric transmission; and establish and charge fees and rates for use of its facilities in consultation with the Wyoming Public Service Commission and other related government entities. The WIA is a good example of state action to promote transmission investment. Figure 13 below shows the corridor of the WCI project between Wyoming and Colorado.

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**Figure 13: Wyoming-Colorado Intertie (TOT 3) Project**

## 15. High Plains Express Conceptual Project

Another proposed major interstate transmission line that includes Colorado is the High Plains Express (HPX) conceptual project. Seven electric utilities, three state agencies, and an independent transmission development company joined in an effort to evaluate the preliminary technical and economic feasibility of this initiative.[33] Many members of the Colorado Coordinated Planning Group have joined in the HPX project, a proactive plan for the expansion and reinforcement of the transmission grid in the states of Wyoming, Colorado, New Mexico and Arizona. The goal of the project is to develop a high-voltage backbone transmission system that will enhance reliability and increase access to renewable and other diverse generation resources within regional energy resource zones.

[33] Colorado Springs Utilities (CSU), Platte River Power Authority (PRPA), Public Service of New Mexico (PNM), Salt River Project (SRP), Trans-Elect, Tri-State G&T, Western Area Power Administration (Western), Xcel Energy, Colorado Clean Energy Development Authority (CEDA), New Mexico Dept. of Energy, Minerals & Natural Resources (NM-EMNR), and the Wyoming Infrastructure Authority (WIA)

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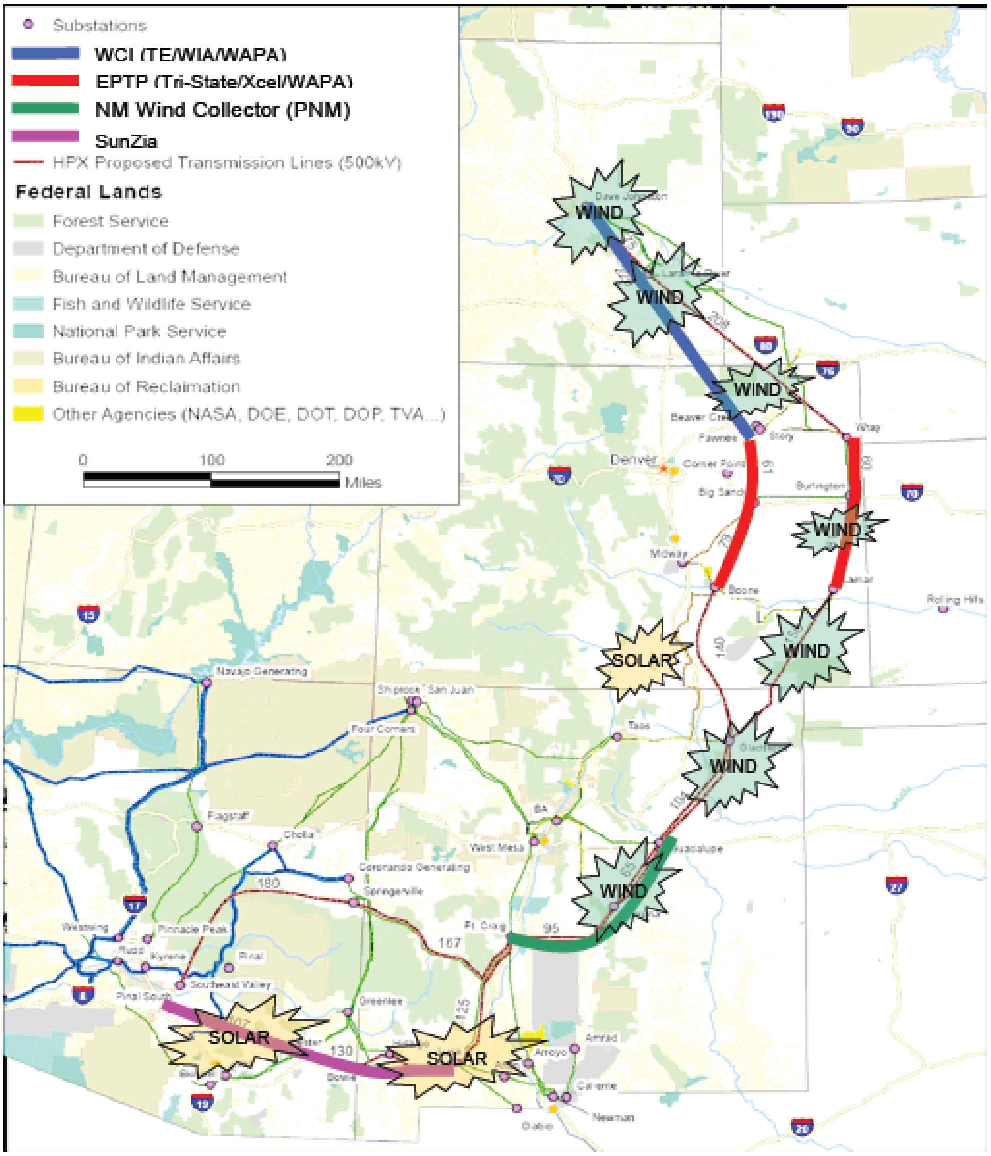


**Figure 14: Conceptual Routing of the HPX Project**

The HPX concept would extend either a double circuit 345 kV or a 500 kV AC transmission system that is used throughout much of the WECC, add North-South and East-West transmission capability, broaden markets for renewable energy, enhance system reliability, and provide markets to make economic transfers of energy that would create potential cost-savings opportunities for customers in Wyoming, Colorado, New Mexico, and Arizona. Figure 14 shows the conceptual routing of HPX project.

Over the next few years, HPX will engage in siting and routing of transmission lines, sequentially developing project segments while assessing applicable laws, quantifying costs and

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proposing cost allocation and cost recovery mechanisms with stakeholder involvement.[34] Installed costs for two 500 kV lines and associated substations are estimated at $5.1 billion (in 2007 dollars), with indicative economics shown for potential major line segments in Table 11 below. As shown in Table 11, effective transmission rates are significantly dependent upon the extent to which a transmission line is utilized. For example for Wyoming-Colorado section of the project, the fixed charge monthly rate would be $3.21 per kW where as the variable rate would be based on the utilization of the transmission lines. At 40% use, the rate would $10.99 per MWh where as at 80% use, the rate would drop to $5.50 per kWh.

**Table 11: HPX Project Effective Transmission Rates**

| Segment | Ave. Miles | Cost ($MM) | Line Losses | Indicative Transmission Rates | | |
|---|---|---|---|---|---|---|
| | | | | $/kw-mo | $/MWh @ 40% Use | $/MWh @ 80% Use |
| Wyoming - Colorado | 335 | $1,366 | 2.4% | $3.21 | $10.99 | $5.50 |
| Colorado - New Mexico | 420 | $1,680 | 3.1% | $3.94 | $13.49 | $6.75 |
| New Mexico - Arizona | 525 | $2,087 | 3.8% | $4.90 | $16.78 | $8.39 |

Source: HPX Project

The HPX project would potentially incorporate two transmission projects already under development in Colorado and within the HPX footprint; Tri-State's Eastern Plains Transmission Project (EPTP), and the Wyoming-Colorado Intertie (WCI).

[34] See Appendix B for the primary summary conclusions of preliminary feasibility study of HPX project.

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## 16. Transmission Planning

A transmission planning process is intended to facilitate the development of electric transmission infrastructure that maintains reliability, meets load growth while improving the efficiency of electric system operations, and responds to service requests under the provision of open and non-discriminatory access to transmission facilities pursuant to FERC requirements. The planning process is to produce system studies that:

a) Provide adequate transmission for network resources in order to reliably and economically serve the utility's load and other network loads
b) Support local transmission systems
c) Provide for interconnection for new generation resources
d) Coordinate new interconnections with other transmission systems
e) Accommodate requests for long-term transmission access

### General Transmission Planning Criteria

The important elements of the overall power system for consideration in planning of a new transmission additions are outlined in Electric Power Research Institute's Transmission Line Reference Book as:

- Real and reactive power flow
- Economics
- Stability
- Interchange capability
- Reliability, and
- Environmental impact

The planning process objective is usually to meet the near-term system need while developing a viable plan for the future needs and respond to the evolution of the overall future transmission system.

### Types of Planning Studies

There are two types of planning studies utilities generally performed on a stand-alone basis or within a coordinated forum; Reliability Studies and Economic Studies.

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**Reliability Studies**

Utilities within Colorado generally conduct reliability studies to ensure that all of NERC, WECC, and local reliability standards are met for each year of the ten year planning horizon, including all customers planned loads and resources. These reliability studies typically are coordinated with the other regional transmission planning organizations.

Reliable electric service is critically important and the risk of economic and other impacts caused by less reliable electrical system is very costly. In 2006, House Bill 06-1325 created the Task Force on Reliable Electricity Infrastructure. Its purpose was to examine a complex and technical set of issues associated with electric infrastructure and to "engage affected stakeholders to develop a comprehensive plan that addresses the state's future electric infrastructure needs for the benefit of Colorado and its citizens." In November 2006, the Task Force issued its report by stating:

> *"The subject matter of electric transmission infrastructure is complex and highly technical, but the basic problem is simple and straightforward: without enough transmission lines in the right places the lights won't stay on. In addition Colorado's ability to ensure continued affordable, reliable electricity and to build a vibrant economy depends on sufficient transmission capability. Today the system is strained and, if current trends continue, there will not be adequate transmission to meet the needs."*

**Economic Studies**

Economic planning studies are performed to identify significant and recurring congestion on the transmission system. Such studies may analyze any, or all, of the following:

(i) the location and magnitude of the congestion
(ii) possible remedies for the elimination of the congestion, in whole or in part
(iii) the associated costs of congestion, and
(iv) the costs associated with relieving congestion through system enhancements (or other means)

Transmission owners also perform, or cause to be performed, economic planning studies at the request of any transmission customer or stakeholder. All economic planning studies performed utilize the WECC basecase data.

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**Transmission Planning Cycle**

In Colorado, transmission owners and operators conduct their transmission planning for a ten year planning horizon. Updates of ten year plans are normally conducted annually and are filed with respective jurisdictional authorities, such as the Colorado Public Utilities Commission under requirements of Rule 3206 and Federal Energy Regulatory Commission (FERC) rules.

**Study Criteria and Guidelines**

Reliability Criteria for System Planning and Service Standards for planning criteria, guidelines, assumptions and data are posted on the OASIS[35] for the interested parties.

**Planning Study Process in Colorado**

Transmission providers in Colorado perform and participate in transmission planning and coordinate their planning with other transmission providers and stakeholders at the regional and sub-regional levels of the Western Interconnection through active participation in the Colorado Coordinated Planning Group (CCPG), WestConnect, and the Western Electricity Coordinating Council (WECC) and participation in the WECC Transmission Expansion Planning Policy Committee (TEPPC) and its Technical Advisory Subcommittee (TAS).

**Colorado Coordinated Planning Group**

The Colorado Coordinated Planning Group (CCPG) is a joint high voltage transmission system planning forum required for the purpose of assuring a high degree of reliability in the planning, development and operation of the high voltage system in the Rocky Mountain region, in accordance with the Joint Transmission Access Principles and the Electric Transmission Service Policy Statement, dated December 16, 1991. The CCPG provides the technical forum required to complete reliability assessments, develop joint business opportunities, and accomplish coordinated planning, under the single-system planning concept in the Rocky Mountain Region of the WECC.

CCPG performs annual transmission studies via a coordinated planning process to ensure that the electric system meet selected Standards and Criteria set forth by the NERC and

[35] Open-Access Same-Time Information System (OASIS)— An electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously.

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WECC.[36] It is the responsibility of each Transmission Planner or Planning Authority to ensure that they are in compliance with NERC Standards. The transmission system performance assessment studies performed for 2008 report specifically addressed NERC Standards TPL-001(N-0 System Performance), TPL-002 (N-1 System Performance), TPL-003 (N-2 System Performance), and TPL-004 (Extreme Contingency).

The studies conducted for 2008 consisted of load flow, transient stability, and voltage stability analyses. The study area consisted of the CCPG footprint, including Southern/Eastern Wyoming and all of Colorado, and can be electrically described as the area bounded by Yellowtail to the north, the DC ties at Rapid City, Stegall, Sidney and Lamar to the east, TOT1A and Jim Bridger to the west, and TOT2A to the south.[37] This study is generally completed annually, or as system conditions warrant.

The CCPG develops transmission system models from models prepared by the WECC to conduct assessments for the near-term (years one through five) and the longer-term (years six through ten) planning horizons. The two base cases included in the 2008 study originated from the 2013 heavy summer loading case and the 2018 heavy summer loading case.[38] These cases were also utilized in the Colorado Long Range Transmission Plan Study.

The CCPG studies cover the steady state analysis as well as transient stability cases. In the steady state analysis all Bulk Electric System high voltage (>= 115kV) bus voltages and non-radial branch flows in the CCPG area are monitored for criteria violations. The transient stability cases include the detailed Sidney DC tie, Stegall DC tie, and Rapid City DC tie models. All Bulk Electric System buses in the study area are monitored for voltage and major generating units in the area are monitored for stability. Table 12 shows CCPG 2008 compliance Report Area Path

[36] CCPG issued its latest NERC/WECC Compliance Report and Reactive Margin Analysis Report on October 6, 2008.
[37] The study participants were; Basin Electric Power Cooperative, Black Hills Energy, Black Hills Power, Colorado Springs Utilities, Platte River Power Authority, Public Service Company of Colorado, Tri-State Generation and Transmission Association, and Western Area Power Administration
[38] Based on CCPG's previous planning studies, CCPG has concluded that the heavy summer loading scenarios cover the most critical system topology and system conditions over the range of forecast system demand levels in the CCPG footprint.

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Flow for Near Term Base Case 2013 Heavy Summer and Base Case Long Term 2018 Heavy Summer.

**Table 12: CCPG 2008 Compliance Report Area Path Flow**

| BASE CASE | AREA PATH FLOW | | |
|---|---|---|---|
| | **TOT3** | **TOT7** | **TOT5** |
| Near Term 2013 Heavy Summer | 1198 | 167 | 845 |
| Long Term 2018 Heavy Summer | 1199 | 66 | 524 |

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## 17. Colorado Long Rang Transmission Planning Group

The Colorado Long Range Transmission Planning Group (CLRTPG) was initiated by the CCPG in January 2004 to jointly explore the potential for the development of a “back-bone” transmission network in Colorado that could benefit all electric Load-Serving Entities (LSEs) in the state. The CLRTPG analyzed the 2018 transmission system model to develop four assessments of specific study scenarios. The assessments included load flow, transient stability and voltage stability analyzes. The results of these analyses were used to develop conceptual transmission plans required to accommodate the study scenario.

In November 2008, the CLRTPG released the “*Colorado Long-Range Transmission Planning Draft Study 2008-2018,*” which was jointly prepared by Public Service Company of Colorado (Xcel Energy), Tri- State Generation and Transmission Association, the Western Area Power Administration, Black Hills Power, Colorado Springs Utilities, and Platte River Power Authority. The objectives of 2008-2018 CLRTP study differ from the 2005-2015 CLRTP Study. Newly enacted legislation has affected 2008-2018 objectives and study methodology. In order to facilitate electric utilities compliance with SB-100, HB1281, and other legislation, the Colorado Public Utilities Commission, in decisions C07- 0829 and C07-1101, relaxed the requirements of “least-cost” resource plan with a “cost-effective” resource plan. The change in the PUC rules made changes to CLRTP study objective from “least-cost” to “cost-effective” transmission planning.

Given the new legislative mandates and based on 2018 load forecasts of the participating utilities Firm Load Obligation of 13,035 MW, the CLRTPG estimated that approximately 1,165 MW of new generation resources will need to be acquired and additional high-voltage transmission lines will be built to deliver the power to the load.[39] Table 13 shows Load Serving Entities’ Forecasted Load and Resource Need for CLRTPG Heavy Summer case.

[39] The resource need of 1165 MW assumes PSCo’s 2007 CRP Preferred Plan is approved by the PUC. See Table xx in the body of this report for PSCo’s Preferred Plan.

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**Table 13: CLRTPG New Resource Need for 2018 Heavy Summer**

| LOAD SERVING ENTITY | FORECASTED LOAD (MW) | NEW RESOURCE NEED (MW) |
|---|---|---|
| Black Hills Power | 462 | 74 |
| Colorado Springs Utilities | 1100 | 153 |
| Platte River Power Authority | 862 | 7 |
| Public Service Company | 7643 | 716 |
| Tri-State G&T | 2968 | 215 |
| **Total** | **13,035** | **1,165** |

The CLRTPG study incorporated SB07-100 four injection zones that were representative of proposed generation zones at that time. A fifth zone has been since identified and added to the proposed generation zones, which is not part of the CLRTPG 2008-2018 study.

The CLRTPG report identifies potential transmission plans that can accommodate the level of generation in the 2018 time frame. The CLRTPG report presents four transmission scenario alternatives for both northern and southern eastern Colorado. Table 14 shows the scenario injection magnitude and zone.

**Table 14: Injection of New Resources (MW) for CLRTPG Study Scenarios**

| SCENARIO | STRESS | ZONE 1 | ZONE 2 | ZONE 3 | ZONE 4 | TOTAL |
|---|---|---|---|---|---|---|
| **A** | South-North | 965 | 0 | 1420 | 568 | **2953** |
| **B** | North-South | 765 | 200 | 1420 | 568 | **2953** |
| **C** | East-West | 740 | 740 | 1380 | 55 | **2915** |
| **D** | Zone 4-Front Range | 105 | 0 | 730 | 2005 | **2840** |

Stakeholders developed four study scenarios as described below. When a scenario proposed to inject excess capacity, i.e. more than required per the summary L&R as shown in Table 1, existing or proposed firm resource output was adjusted to maintain load and resource balance. The injection levels were chosen with consideration of meeting or exceeding Colorado RPS requirements and resource planning requests in 2018. For the CLRTPG power flow study, technology type was not considered; therefore, resources were modeled at nameplate output. Appendix C provides greater injection location detail for each scenario.

The following changes were made to *2018HS1*[40] review case to develop the benchmark case:

[40] *2018HS1* refers to heavy summer 2018 scenario

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Deleted EPTP Project elements[41], as discussed earlier EPTP's status is unknown at this time;

- Added transmission changes by adding bus, transformer or increasing line ratings;
- Changed transformer properties;
- Changed load power factor; and
- Made corrections to generating units

The CLRTPG study employed five major principles to meet the study objectives:

1) Conduct as an open and transparent process.
2) Conduct as a joint planning study with multiple utilities.
3) Comply with NERC / WECC criteria.
4) Efficiently use transmission corridors by
    a) Proposing to use existing corridors where feasible, and
    b) Reasonably sizing the capability new corridors.
5) Develop potential transmission solutions that address reliability and do not necessarily endorse or confirm proposed resource plans

The 2018HS1 WECC review case was used to form the benchmark models for the CLRTPG 2008-2018 study.[42] The study participants reviewed and modified the case to accurately represent current load forecasts, regional transmission commitments, and generation projects. The benchmark models included some transmission projects that have been identified through other planning forums. Some of the significant projects are shown in Table 15 below. The CLRTPG study was also coordinated with other CCPG and LSE studies, primarily those associated with Colorado's SB07-100.

[41] As discussed earlier in Tri-State's section, the EPTP's status is unknown at this time.
[42] CLRTPG Study is available at: http://www.westconnect.com/planning_ccpg_lr.php

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**Table 15: Major Transmission Projects Modeled in the CLRTPG Benchmark Case**

| TRANSMISSION PROJECT | PURPOSE | ENTITY | ISD |
|---|---|---|---|
| San Luis Valley-Walsenburg 230 kV (single circuit) | Local Reliability | TSGT | 2012 |
| Wray – Burlington 230 kV | Local Reliability | TSGT | 2015 |
| Beaver Creek (Story) – Erie 230 kV | Serve Native Load | WAPA | 2010 |
| Miracle Mile – Ault 230 kV Line | Increase TOT 3 | WAPA | 2010 |
| Comanche – Daniels Park 345 kV | Accommodate 750 MW Comanche Unit 3 | PSCo | 2009 |
| Midway – Waterton 345 kV | Accommodate 500 MW Generation Near Midway | PSCo | 2012 |
| Weld – Boyd – Flatiron 230 kV | Increase Local Load Serving Capability and Reliability | WAPA | 2018 |

The overall potential transmission projects that resulted from the CLRTPG study includes the projects listed in Table 16 below and are shown in Figure 15 below. The projects identified in the CLRTPG study are non-committed or as it is stated by the CLRTPG,

"…not necessarily recommendations or commitments by any particular party, but this study indicated that they have the potential to reliably accommodate additional resources, enhance transmission system performance, and have merit for long-range plans and additional study."

**Table 16: CLRTPG 2008-2018 Study Summary Results**

| TRANSMISSION PROJECT | VOLTAGE LEVEL (KV)* | COST (M$)+ |
|---|---|---|
| Energy Center ** - Burlington | 500/345 | 70 |
| Energy Center-Burlington-Big Sandy-Road 125-Missile Site (SB07-100) | 500/345 | 160 |
| Energy Center – Comanche (SB07-100) | 500/345 | 80 |
| Energy Center – Lamar (SB07-100) | 230 | 10 |
| Lamar – Vilas (SB07-100) | 230/345 | 30 |
| Pawnee-Daniels Park & Smoky Hill-Daniels Park (SB07-100) | 345 | 65 |
| Ault – Cherokee | 230 | 65 |
| Wyoming – Colorado Intertie | 345 | *** |
| San Luis Valley – Calumet (SB07-100) | 230 | 115 |
| Calumet – Comanche (SB07-100) | 345 | 65 |
| Calumet – Walsenburg | 230 | 10 |
| **TOTAL** | | **670** |

Source: CLRTPG 2008-2018 Draft Study Report

+ The costs represent 2008 dollars and are considered to have +/- 30% accuracy

Table 16 Notes:

* Specific voltages have not been recommended. Preliminary studies show benefit to higher voltage operation, but for reasonable project implementation, some may need to be built at higher voltages, but initially operated at a lower voltage.

** Energy Center is in close proximity (within 20 miles) of Lamar Substation

*** Independent project; no costs provided

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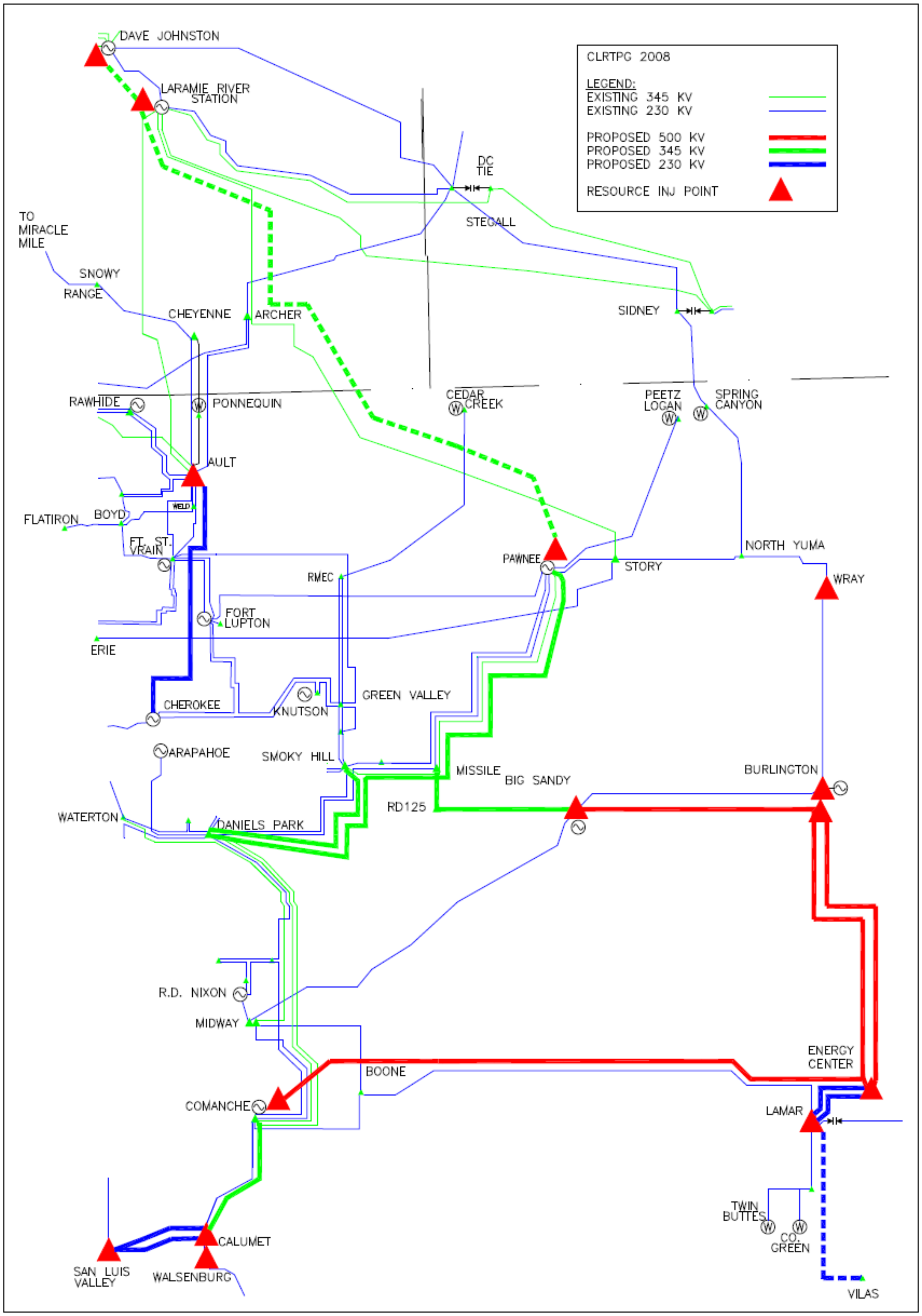
**Figure 15: CLRTPG 2008-2018 Overall Proposed Potential Transmission Plans**



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According to CLRTPG study report, the projects listed in Table 17 below, are in addition to other planned transmission projects that have been identified in other planning forums, and are in various stages of implementation. Those projects are also considered to be part of the ten-year plan, and are listed in Table xx below.

**Table 17: CCPG Other Bulk Transmission Projects Planned for the 10 Years Horizon**

| TRANSMISSION PROJECT | ENTITY | IN-SERVICE DATE | COST (M$)* |
|---|---|---|---|
| Comanche-Daniels Park 345 kV Transmission Project | PSCo | 2009 | 150 |
| Beaver Creek (Story)-Erie 230 kV Line | WAPA | 2010 | 55 |
| Miracle Mile – Ault 230 kV Line | WAPA | 2010 | 90 |
| Midway – Waterton 345 kV Transmission Project | PSCo | 2012 | 35 |
| Pawnee – Smoky Hill 345 kV Transmission Project | PSCo | 2013 | 130 |
| Burlington – Wray 230 kV Transmission Project | TSGT | 2015 | 30 |
| Weld – Boyd – Flatiron 230 kV Project | WAPA | 2018 | 35 |
| **TOTAL** | | | **525** |

***** The costs represent 2008 dollars and are considered to have +/- 30% accuracy

## Details of CLRTPG Study (2008-2018)

The CLRTPG studied four scenarios in order (from Scenario A to Scenario D). As transmission plans were developed for a particular scenario, they were carried forth into subsequent scenario studies. For example, Scenario A stressed the system from the South to the North; Scenario B stressed North to South, Scenario C stressed East to West and Scenario D stressed South central to North. The CLRTPG used the following process to develop bulk power system transmission plans and determine the segments' ability to deliver proposed resource output under steady state and single contingency conditions for all four scenarios:[43]

[43] Underlying or pre-existing transmission issues, such as overloads or voltage criteria violations, were not specifically addressed in the CLRTPG study unless a participant identified a remedy when results were reviewed by the participants. For example, it is reported in the CLRTPG Draft Study, "with the Scenario D injections, several underlying facilities become overloaded under single contingency (N- 1) conditions which indicated additional injections are not feasible without costly upgrades of the lower level transmission system or implementing generation curtailment."

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1) Perform a benchmark analysis of the system to provide a baseline of system performance.
2) Add Scenario A resource additions and compare system performance to the performance of the benchmark case.
3) Develop and evaluate transmission alternatives to alleviate any system intact and contingency performance issues.
4) Study Scenario B resource additions, keeping the transmission plans developed from Scenario A.
5) Develop and evaluate additional transmission alternatives to alleviate any system intact and contingency performance issues.
6) Study Scenario C resource additions, keeping the transmission plans developed from Scenarios A and B.
7) Develop and evaluate additional transmission alternatives to alleviate any system intact and contingency performance issues.
8) Study Scenario D resource additions, keeping transmission alternatives developed from previous scenarios.

It should also be noted that the CLRTPG study did not include projects being considered by the Load Serving Entities' normal budgeting process. The Study only considered the costs associated with the new transmission additions. As most of the transmission plans identified in the CLRTPG study were reaffirmed through the SB100 studies, cost estimates for those projects were provided otherwise, common engineering unit costs were used to estimate the magnitude of transmission investment expected in the ten-year timeframe to support the modeled level of generation. The costs represent 2008 dollars and are considered to have +/- 30% accuracy.

**The CLRTPG Study Results Summary**

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Table 18 shows the summary result of all four scenarios with the injection points and the amount of injection in the order of Scenario A to Scenario D.

**Table 18: Summary of the CLRTPG Bulk Power Transmission Scenario Study**

| SCENARIO | ZONE | INJECTION LOCATION | INJECTION AMOUNT (MW) | TOTAL |
|---|---|---|---|---|
| A<br><br>South North Stressed | 1 | Ault | 55 | 2,953 |
| | 1 | Pawnee | 500 | |
| | 1 | Peetz-Logan | 410 | |
| | 3 | Energy Center | 650 | |
| | 3 | Lamar (new) | 770 | |
| | 4 | San Luis Valley | 445 | |
| | 4 | Walsenburg | 123 | |
| B<br><br>North South Stressed | 1 | Ault | 55 | 2,953 |
| | 1 | Pawnee | 500 | |
| | 1 | Peetz-Logan | 210 | |
| | 2 | Corner Point/Missile | 200 | |
| | ZW1 | LRS | 0 | |
| | ZW2 | DJ | 0 | |
| | 3 | Energy Center | 650 | |
| | 3 | Lamar (new) | 770 | |
| | 4 | San Luis Valley | 445 | |
| | 4 | Walsenburg | 123 | |
| C<br><br>East West Stressed | 1 | Ault | 110 | 2,915 |
| | 1 | Pawnee | 410 | |
| | 1 | Peetz-Logan | 165 | |
| | 1 | Wray | 55 | |
| | 2 | Burlington | 630 | |
| | 2 | Big Sandy | 110 | |
| | 2 | Corner Point/Missile | 0 | |
| | 3 | Energy Center | 650 | |
| | 3 | Lamar (new) | 730 | |
| | 4 | San Luis Valley | 0 | |
| | 4 | Walsenburg | 55 | |
| D<br><br>South Central Colorado | 1 | Ault | 0 | 2,840 |
| | 1 | Pawnee | 65 | |
| | 1 | Peetz-Logan (new) | 40 | |
| | 1 | Wray | 0 | |
| | 2 | Burlington | 0 | |
| | 2 | Big Sandy | 0 | |
| | 2 | Corner Point/Missile | 0 | |
| | 3 | Energy Center | 650 | |
| | 3 | Lamar (new) | 80 | |
| | 4 | San Luis Valley | 1000 | |
| | 4 | Walsenburg | 1005* | |

* 1000 MW solar generation and 5 MW of generation associated with GDA8, identified in Colorado Senate Bill 91

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As noted above, the CLRTPG studied four scenarios in the order of Scenario A to Scenario D. As transmission plans were developed for Scenario A, they were carried forth into subsequent scenario studies, for example, Scenario B, and on to Scenario C, and D.

Table 19, is a summary table showing the potential transmission projects with the associated transmission project voltage level, and costs.

**Table 19: Summary of the CLRTPG Bulk Power Transmission Projects and Cost**

<table>
<tr><th>SCENARIO</th><th>TRANSMISSION PROJECT</th><th>VOLTAGE LEVEL (KV)</th><th>ESTIMATED COST (2008 $M)</th><th>TOTAL</th></tr>
<tr><td rowspan="5">A</td><td>Energy Center-Burlington</td><td>500/345</td><td>70</td><td rowspan="5">350</td></tr>
<tr><td>Energy Center-Burlington-Big Sandy-Road 125-Missile Site</td><td>500/345</td><td>160</td></tr>
<tr><td>Energy Center-Comanche</td><td>500/345</td><td>80</td></tr>
<tr><td>Energy Center-Lamar</td><td>230</td><td>10</td></tr>
<tr><td>Lamar-Vilas</td><td>230/345</td><td>30</td></tr>
<tr><td rowspan="2">B</td><td>Pawnee-Daniels Park 345 kV Line;<br>Smoky Hill-Daniels park 345 kV Line</td><td>345</td><td>65</td><td rowspan="2">130</td></tr>
<tr><td>Ault-Cherokee 230 kV Line</td><td>230</td><td>65</td></tr>
<tr><td>C</td><td colspan="3">No major additions were needed beyond those developed for Scenarios A and B</td><td>-</td></tr>
<tr><td rowspan="3">D</td><td>San Luis Valley-Calumet</td><td>230</td><td>115</td><td rowspan="3">190</td></tr>
<tr><td>Calumet-Comanche</td><td>345</td><td>65</td></tr>
<tr><td>Calumet-Walsenburg</td><td>230</td><td>10</td></tr>
<tr><td colspan="4">TOTAL COST FOR ALL TRANSMISSION PROJECTS (2008-2018)</td><td>670</td></tr>
</table>

Within the scenario A studies, it was verified that the proposed Pawnee – Smoky Hill 345kV line would be sufficient to accommodate the additional resources modeled at Pawnee and Peetz-Logan. The CLRTPG study also notes that San Luis Valley – Walsenburg single-circuit 230kV line and the Midway – Waterton 345kV line, which were in the benchmark models, appeared to be sufficient to accommodate the 575 MW of injection at San Luis Valley and Walsenburg. However, the CLRTPG notes that since there was over 1400 MW of new resource injection in the vicinity of Lamar and Energy Center, additional transmission had to be built from that region to the Front Range load centers.

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For the level of resources studied, the study determines three high-voltage lines provide optimum results, which is reported to be consistent with previous studies and the Eastern Plains Transmission Project (EPTP). Sensitivity studies showed that if the lines were operated at 500kV instead of 345kV, there was a potential for even higher resource additions in the region.

No resource additions were modeled at Vilas. However, the CLRTPG Study refers to SB 07-100 studies identifying that project of having the potential to deliver resources from renewable development areas in Baca County if the high voltage transmission projects from Lamar/Energy Center are built first.

For the Scenario B studies, it was assumed that the projects identified from the Scenario A studies would be in place for Scenario B injection points. This included the three high-voltage transmission lines out of Energy Center indentified in Scenario A studies. It should also be noted as part of Scenario B, about 1000 MW of new resources were modeled northeast of the Denver-metro area which required additional transmission from the Pawnee substation into the Denver-metro load center. The CLRTPG Study references previous SB 07-100 and WCI studies as demonstrating the need for an Ault – Cherokee transmission project, and the studies of the WCI project with 910 MW of additional resources in Wyoming being scheduled to Colorado loads yielded similar results.

As for Scenario C, some new resource additions were modeled in the eastern portion of the study footprint that were not included in Scenarios A or B. These included Burlington, Wray, and Big Sandy. The new generation at those locations was about 800 MW. The same methodology of the Scenario B studies were used for the Scenario C studies assuming that the projects identified from the Scenario A and Scenario B studies would be in place for the Scenario C studies. Scenario C studies indentified no major

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additions needed beyond those developed for Scenarios A and B. The CLRTPG Study point out that it is likely due to modeling the Energy Center to Missile Site line to have connections at Burlington and Big Sandy. If the line is constructed in this manner, it results in an Energy Center to Burlington line and a line from Burlington to Big Sandy, Road 125, and Missile Site. This allows delivery of resources in the east to Front Range loads via Missile Site and Road 125 substations.

Finally, for the Scenario D approximately 2000 MW of new resources was added in south-central Colorado. The existing transmission lines in the region were not adequate to handle the additional resources thus requiring new transmission lines. It was verified that the following transmission projects indentified under the SB 07-100 Studies would provide adequate transmission capacity for Scenario D:

**San Luis Valley – Calumet:** This is proposed as a double-circuit 230kV project. Studies demonstrated that 230kV construction would enable approximately 1000 MW of new generation out of the San Luis Valley.

**Calumet – Comanche:** This project delivers the generation from both the San Luis Valley and the Walsenburg substations to the Front Range transmission system. The project has a suggested operating voltage of 345kV to allow for the combined injections in the region.

**Calumet – Walsenburg:** This project enhances reliability of the overall system and allows injections at Walsenburg to reach the bulk transmission system.

The CLRTPG study also performed sensitivity studies which indicated no additional injection capability was gained by increasing the voltage between San Luis Valley and Calumet from 230 kV to 345 kV mainly due to the performance limitations north of the San Luis Valley.

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## The CLRTPG Summary Conclusion

The CLRTPG 2018 Study identified bulk system transmission plans and improvements that could potentially integrate new resources. The Study was based on a resource need of 1,165 MW in 2018. However, since the resource injections for each of the four scenarios exceeded the projected resource need of 1,165 MW for 2018; scenario models were developed to analyze transmission solutions across the CCPG footprint. The following conclusion is from the CLRTPG 2018 Study:

> 1- Results from Scenario A indicated that building high voltage transmission from the Lamar/Energy Center region to the Front Range system would allow delivery of new generation resources in southeastern Colorado. A minimum of two high voltage lines should be developed for any additional resources in the region. At least one of the lines should terminate at or near Comanche, and the other should terminate at or near Missile Site. To accommodate new resources in eastern Colorado, the line to Missile Site could be routed so that it connects into the Burlington and Big Sandy substations. Studies showed that three lines would increase injection capability, specifically a line from Lamar/Energy Center to Burlington. Although the lines should have a minimum operating voltage of 345kV, it may be prudent to explore constructing the projects for 500kV operation when conditions warrant. Studies showed potential increase in injection capabilities at the higher voltage.
>
> Other potential transmission plans for the southeast Colorado region included transmission south of Lamar. Such transmission would allow for additional resources in Baca County, but only if the high voltage transmission out of Lamar/Energy Center is developed to allow new resources to be delivered to load.

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The transmission plan developed from Scenario A has many elements in common with the previous Eastern Plains Transmission Project. Both plans include transmission from the Lamar area to Comanche, Burlington, Big Sandy, and Road 125. However, the present plan interconnects with the PSCo system at Missile Site, instead of connecting with the PSCo/Western system at Midway.

2- Results from Scenario B indicated that additional high voltage transmission from Pawnee may facilitate delivery of new generation resources in northeast Colorado and Wyoming. Suggested projects include a Pawnee – Daniels Park 345kV project and a Smoky Hill – Daniels Park 345kV transmission project.

Also, SB100 and WCI studies have shown the need for an Ault – Cherokee transmission project. New transmission from Ault to Cherokee would allow resource additions at or near Ault, as well as allow for increased transfer capability across WECC Path 40 (TOT 7). Therefore, both the Pawnee – Daniels Park, and the Ault – Cherokee are included in transmission plans for both Scenario B sensitivities studied: resource additions at or near the Pawnee and Ault substations; or for a Wyoming – Colorado Intertie Project.

3- Results from Scenario C indicated that the transmission plans that resulted from Scenarios A and B can also allow delivery of new generation resources in eastern Colorado at locations at or near Burlington, Wray, and Big Sandy. The transmission would have to be implemented so that there is a high-voltage path between Burlington, Big Sandy, Road 125, and Missile Site to allow delivery of the additional resources in the east.

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4- Results from Scenario D indicated that new high-voltage transmission is needed between the San Luis Valley and Comanche. To allow for resource additions in the vicinity of Walsenburg, studies showed benefit to implementing a new 345 kV substation near Walsenburg, called Calumet, and 345 kV transmissions between Calumet and Comanche. Sensitivity studies indicated that there was no benefit gained by increasing the voltage between San Luis Valley and Calumet from 230 kV to 345 kV. This was due to the performance limitations north of the San Luis Valley. Future studies should be performed to explore transmission upgrades north of San Luis Valley.

5- As specific projects are considered for construction, detailed studies involving transient and voltage stability, lighter loading conditions, operating voltage, transfer capability, and impacts to WECC Rated Paths (TOT's) may be required.

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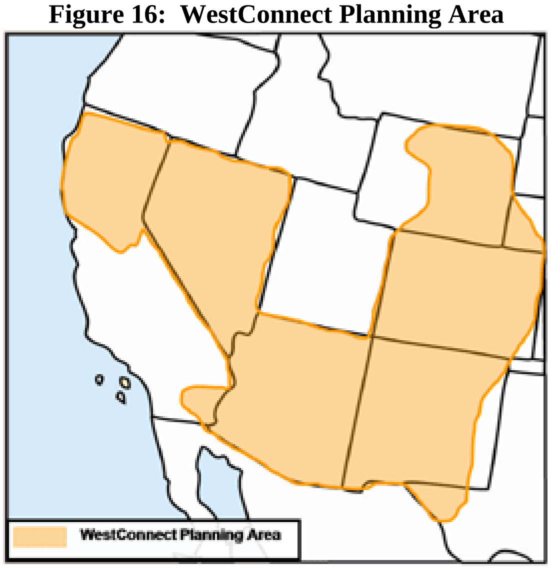
## 18. WestConnect

WestConnect is a forum for transmission planning within the Western Interconnection, comprised of utilities providing transmission services in the Southwest.[44] The WestConnect planning process by definition is inclusive of the sub-regional planning efforts of Southwest Transmission Planning Group (SWAT), Colorado Coordinated Planning Group (CCPG), Sierra Subregional Planning Group (SSPG) and any future Subregional Transmission Planning Group (STPG) that forms within the WestConnect planning area. See Figure 16 for WestConnect Planning Area

**Figure 16: WestConnect Planning Area**




Within WestConnect, sub-regional planning activities are undertaken by the CCPG. A ten year planning regime guides the planning efforts of the CCPG.

[44] WestConnect was formed under a memorandum of understanding (MOU) among twelve transmission providing electric utilities in the Western Interconnection. The purposes of WestConnect are to investigate the feasibility of wholesale market enhancements, work cooperatively with other Western Interconnection organizations and market shareholders and address seams issues in the appropriate forums. WestConnect has initiated an effort to facilitate and coordinate regional transmission planning across the WestConnect footprint. Three major transmission providers in Colorado; Public Service Company of Colorado, Tri-State Generation & Transmission Assoiciation, and Western Area Power Administration are parties to the WestConnect MOU.

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The WestConnect planning process has been organized to strategically coordinate these sub-regional planning efforts and encourage the consistent participation of WestConnect Subregional Transmission Planning (STP) Agreement members and any additional interested stakeholders or customers. The STP Agreement establishes a formal commitment of the signatory parties to fund and oversee the WestConnect sub-regional planning process.[45]

The process has also been designed to synchronize and coordinate with the Western Electricity Coordinating Council ("WECC") regional planning process and its Transmission Expansion Planning Policy Committee ("TEPPC") regional transmission congestion study efforts. Coordination is accomplished through a layered approach utilizing existing planning organizations to perform local, sub-regional and regional planning within the Western Interconnection as depicted in the Figure xx. The WestConnect sub-regional planning process consists of activities represented each of the single STP circles.

The WestConnect planning process utilizes a planning cycle concept depicted in Figure 17. It assumes two consecutive planning cycles overlap by a given period of time. The overlap of two study cycles offers stakeholders a window of opportunity to be involved and provide input on a variety of levels.

[45] Available at: http://www.westconnect.com/

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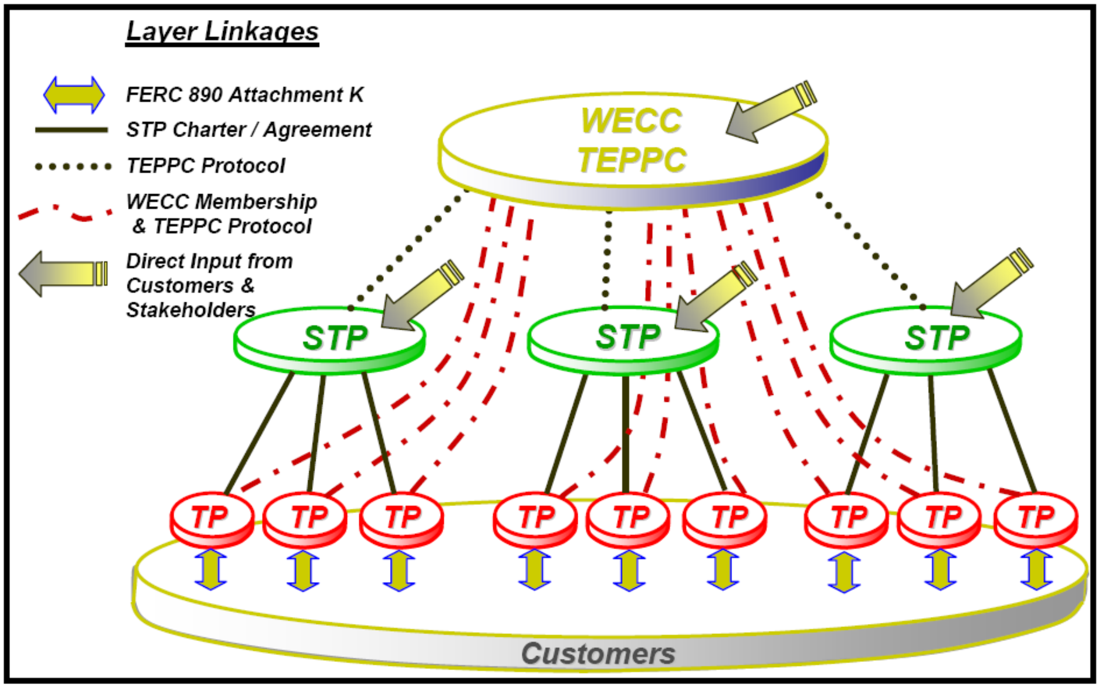
**Figure 17: Coordinated Western Interconnection Planning Processes**




Two of the nine recommendations of WestConnect are worth nothing. WestConnect recommended its members should work to:

- Provide a single TTC/ATC table or map open to stakeholder examination on the website.
- Create a single database of existing transmission facilities for all WestConnect entities.

Available Transfer Capability (ATC) and Total Transfer Capability (TTC) are two important transmission indicators useful to stakeholders to gauge the availability and overall conditions of transmission system for energy systems development. Other parts of the country have begun to post the ATC on website. See Figure 18 for Northern Tier Transmission Group ATC information posted on its website.

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NORTHERN TIER TRANSMISSION GROUP

## ATC INFORMATION as of 12/01/08

*** !! IMPORTANT DISCLAIMER!! Northern Tier Transmission Group ("NTTG") documents are produced using historical or modeled Available Transfer Capability ("ATC") information provided by the transmission providers funding its activities. Historical or modeled records have not been adjusted unless indicated, may contain errors, and may not be consistent between transmission providers. If errors or discrepancies between records are discovered, NTTG documents may not be corrected. These documents are illustrative and should not be used to make transmission business decisions. For the avoidance of doubt, each transmission provider calculates the ATC of the transmission facilities it owns or operates according to the methodology set forth in Attachment C of its Open Access Transmission Tariff ("OATT"), and posts ATC on its Open Access Same-time Information System ("OASIS"). Transmission service must be requested over the OASIS of each transmission provider with whom you wish to do business. Transmission service requests are processed by each transmission provider according to the terms and conditions of its OATT.***

| WECC # (if applicable) | Path Common Name (if applicable) | Direction | Company | OASIS SEGMENT NAME | FROM: Point of Receipt (POR) | TO: Point of Delivery (POD) | kV | Between hours | WINTER (NOV '08 - MAY '09) TTC | Total Firm Obligations | Network | LT Firm PTP | TRM | CBM | ATC (Long term only) | SUMMER (JUN '09 - OCT '09) TTC | Total Firm Obligations | Network | LT Firm PTP | TRM | CBM | ATC (Long term only) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 33 | | E to W | Deseret Power | BOZ-MDGT | BOZ | MONA | 345 | All | 565+80*** | 565+80** | 0 | 565+80** | 0 | 0 | 0 | 565+80*** | 565+80** | 0 | 565+80*** | 0 | 0 | 0 |
| 33 | | W to E | Deseret Power | MDGT-BOZ | MONA | BOZ | 345 | All | 645 | 351 | 0 | 351 | 0 | 0 | 294 | 645 | 354 | 0 | 354 | 0 | 0 | 291 |
| - | | S to N | Deseret Power | BOZ-VNL | BOZ | VNL | 138 | All | 115 | 91 | 0 | 91 | 0 | 0 | 24 | 115 | 91 | 0 | 91 | 0 | 0 | 24 |
| - | | N to S | Deseret Power | VNL-BOZ | VNL | BOZ | 138 | All | 115 | 90 | 0 | 90 | 0 | 0 | 25 | 115 | 90 | 0 | 90 | 0 | 0 | 25 |
| - | | W to E | Deseret Power | BOZ-SWR | BOZ | SWR | 138 | All | 115 | 35 | 0 | 35 | 0 | 0 | 80 | 115 | 0 | 0 | 0 | 0 | 0 | 115 |
| - | | E to W | Deseret Power | SWR-BOZ | SWR | BOZ | 138 | All | 115 | 0 | 0 | 0 | 0 | 0 | 115 | 115 | 0 | 0 | 0 | 0 | 0 | 115 |
| 18 | AMPS | N to S | Idaho Power | WIPCO/PACE-IPCO/HTSP-IPCO | HTSP | IPCO | 230 | All | 250 | 250 | 80 | 170 | 0 | 0 | 0 | 250 | 250 | 80 | 170 | 0 | 0 | 0 |
| 18 | AMPS | N to S | Idaho Power | WIPCO/PACE-PACE/MLCK-BRDY | MLCK | BRDY | 230 | All | 250 | 250 | 80 | 170 | 0 | 0 | 0 | 250 | 250 | 80 | 170 | 0 | 0 | 0 |
| 18 | AMPS | N to S | Idaho Power | WIPCO/NWMT-IPCO/JEFF-IPCO | JEFF | IPCO | 161 | All | 87 | 87 | 0 | 87 | 0 | 0 | 0 | 87 | 87 | 0 | 87 | 0 | 0 | 0 |
| 18 | AMPS | S to N | Idaho Power | WIPCO/IPCO-PACE/IPCO-HTSP | IPCO | HTSP | 230 | All | 184 | 171 | 0 | 171 | 0 | 0 | 13 | 180 | 171 | 0 | 171 | 0 | 0 | 9 |
| 18 | AMPS | S to N | Idaho Power | WIPCO/PACE-PACE/BRDY-MLCK | BRDY | MLCK | 230 | All | 184 | 171 | 0 | 171 | 0 | 0 | 13 | 180 | 171 | 0 | 171 | 0 | 0 | 9 |
| 18 | AMPS | S to N | Idaho Power | WIPCO/IPCO-NWMT/IPCO-JEFF | IPCO | JEFF | 161 | All | 70 | 5 | 5 | 0 | 0 | 0 | 65 | 87 | 5 | 5 | 0 | 0 | 0 | 82 |
| 14 | ID-NW | W to E | Idaho Power | WIPCO/BPAT-IPCO/LAGRANDE-IPCO | LaGrande | IPCO | 230/138 | All | 350 | 350 | 350 | 0 | 0 | 0 | 0 | 350 | 350 | 350 | 0 | 0 | 0 | 0 |
| 14 | ID-NW | W to E | Idaho Power | WIPCO/PACW-IPCO/ENPR-IPCO | ENPR | IPCO | 230 | All | 400 | 68 | 68 | 0 | 0 | 0 | 332 | 400 | 59 | 59 | 0 | 0 | 0 | 341 |
| 14 | ID-NW | W to E | Idaho Power | WIPCO/AVA-IPCO/LOLO-IPCO | LOLO | IPCO | 230 | All | 400 | 155 | 155 | 0 | 0 | 0 | 245 | 340 | 155 | 155 | 0 | 0 | 0 | 185 |
| 14 | ID-NW | W to E | Idaho Power | NORTHWEST to IPCO | LaGrande/ENPR/LOLO | IPCO | 230/138 | All | 1150 | 573 | 573 | 0 | 247 | 330 | 0 | 1090 | 564 | 564 | 0 | 196 | 330 | 0 |
| 14 | ID-NW | E to W | Idaho Power | WIPCO/IPCO-BPAT/IPCO-LAGRANDE | IPCO | LaGrande | 230/138 | All | 413 | 348 | 0 | 348 | 0 | 0 | 65 | 350 | 348 | 0 | 348 | 0 | 0 | 2 |
| 14 | ID-NW | E to W | Idaho Power | WIPCO/IPCO-PACW/IPCO-ENPR | IPCO | ENPR/M500 | 230/500 | All | 1587 | 1587 | 0 | 1587 | 0 | 0 | 0 | 1587 | 1587 | 0 | 1587 | 0 | 0 | 0 |
| 14 | ID-NW | E to W | Idaho Power | WIPCO/IPCO-AVA/IPCO-LOLO | IPCO | LOLO | 230 | All | 367 | 75 | 0 | 75 | 0 | 0 | 292 | 367 | 75 | 0 | 75 | 0 | 0 | 292 |
| 14 | ID-NW | E to W | Idaho Power | IPCO to NORTHWEST | IPCO | LaGrande/ENPR/LOLO | 500/230/138 | All | 2304 | 2010 | 0 | 2010 | 0 | 0 | 294 | 2304 | 2010 | 0 | 2010 | 0 | 0 | 294 |
| 16 | | N to S | Idaho Power | WIPCO/IPCO-SPPC/IPCO-M345 | IPCO | M345 | 345 | All | 500 | 42 | 17 | 25 | 0 | 0 | 458 | 500 | 42 | 17 | 25 | 0 | 0 | 458 |
| 16 | | S to N | Idaho Power | WIPCO/SPPC-IPCO/M345-IPCO | M345 | IPCO | 345 | All | 262 | 262 | 262 | 0 | 0 | 0 | 0 | 262 | 262 | 262 | 0 | 0 | 0 | 0 |
| 17 | Borah West | E to W | Idaho Power | WIPCO/PACE-IPCO/BORA-IPCO | BORA | IPCO | 345/230/138 | All | 2557 | 2480 | 731 | 1749 | 0 | 0 | 77 | 2557 | 2257 | 508 | 1749 | 0 | 0 | 0 |
| 17 | Borah West | W to E | Idaho Power | WIPCO/IPCO-PACE/IPCO-BORA | IPCO | BORA | 345/230/138 | All | Capacity Not Defined | 35 | 5 | 30 | 0 | 0 | ND* | Capacity Not Defined | 35 | 5 | 30 | 0 | 0 | ND* |
| 19 | Bridger | E to W | Idaho Power | WIPCO/PCWY-IPCO/JBSN-IPCO | JBSN | IPCO | 345 | All | 707 (IPC Share) | 707 | 707 | 0 | 0 | 0 | 0 | 707 (IPC Share) | 707 | 707 | 0 | 0 | 0 | 0 |
| 19 | Bridger | W to E | Idaho Power | WIPCO/IPCO-PCWY/IPCO-JBSN | IPCO | JBSN | 345 | All | Capacity Not Defined | 0 | 0 | 0 | 0 | 0 | ND* | Capacity Not Defined | 0 | 0 | 0 | 0 | 0 | ND* |
| 18 | AMPS | NW to NWMT.System | NWMT | WS/NWMT/AVA-NWMT/HTSP-NWMT.SYSTEM/ | HTSP | NWMT.SYSTEM | 230 | All | 250 | 13 | 13 | 0 | 0 | 0 | 67 | 250 | 39 | 39 | 0 | 0 | 0 | 81 |
| 18 | AMPS | NWMT.System to NW | NWMT | WS/NWMT/NWMT-AVA/NWMT.SYSTEM-HTSP/ | NWMT.SYSTEM | HTSP | 230 | All | 250 | 37 | 0 | 37 | 0 | 0 | 43 | 250 | 40 | 0 | 40 | 0 | 0 | 40 |
| 18 | AMPS | NWMT.System to SW | NWMT | WS/NWMT/NWMT-PPW/NWMT.SYSTEM-BOBR/ | NWMT.SYSTEM | BOBR | 230 | All | 250 | 80 | 0 | 80 | 0 | 0 | 0 | 250 | 80 | 0 | 80 | 0 | 0 | 0 |
| 18 | AMPS | NWMT.System to SW | NWMT | WS/NWMT/NWMT-PPW/NWMT.SYSTEM-JEFF/ | NWMT.SYSTEM | JEFF | 161 | All | 87 | 87 | 0 | 87 | 0 | 0 | 0 | 87 | 87 | 0 | 87 | 0 | 0 | 0 |
| 18 | AMPS | NWMT.System to SW | NWMT | WS/NWMT/NWMT-NWMT/NWMT.SYSTEM-MLCK/ | NWMT.SYSTEM | MLCK | 230 | All | 250 | 80 | 0 | 80 | 0 | 0 | | 250 | 80 | 0 | 80 | 0 | 0 | 0 |
| 18 | AMPS | NWMT.System to SW | NWMT | WS/NWMT/NWMT-NWMT/MLCK-NWMT.SYSTEM/ | MLCK | NWMT.SYSTEM | 230 | All | 184 | 0 | 0 | 0 | 0 | 0 | 59 | 180 | 0 | 0 | 0 | 0 | 0 | 50 |
| 18 | AMPS | SW to NWMT.System | NWMT | WS/NWMT/PPW-NWMT/BOBR-NWMT.SYSTEM/ | BOBR | NWMT.System | 230 | All | 184 | 0 | 0 | 0 | 0 | 0 | 59 | 180 | 0 | 0 | 0 | 0 | 0 | 50 |
| 18 | AMPS | SW to NWMT.System | NWMT | WS/NWMT/PPW-NWMT/JEFF-NWMT.SYSTEM/ | JEFF | NWMT.SYSTEM | 161 | All | 72 | 5 | 0 | 5 | 0 | 0 | 67 | 70 | 5 | 5 | 0 | 0 | 0 | 65 |
| 8 | Path 8 | NW to NWMT.System | NWMT | WS/NWMT/BPAT-NWMT/BPAT.NWMT-NWMT.SYSTEM/ | BPAT.NWMT | NWMT.SYSTEM | 500-230-115 | All | 864 | 281 | 150 | 131 | 221 | 0 | 362 | 864 | 391 | 382 | 9 | 221 | 0 | 252 |
| 8 | Path 8 | NW to NWMT.System | NWMT | WS/NWMT/AVA-NWMT/BURKE-NWMT.SYSTEM/ | BURKE | NWMT.SYSTEM | 115 | All | 132 | 0 | 0 | 0 | 0 | 0 | 132 | 132 | 0 | 0 | 0 | 0 | 0 | 132 |
| 8 | Path 8 | NWMT.System to NW | NWMT | WS/NWMT/NWMT-BPAT/NWMT.SYSTEM-BPAT.NWMT/ | NWMT.SYSTEM | BPAT.NWMT | 500-230-115 | All | 608 | 225 | 0 | 225 | 0 | 0 | 383 | 608 | 250 | 0 | 250 | 0 | 0 | 358 |
| 8 | Path 8 | NWMT.System to NW | NWMT | WS/NWMT/NWMT-AVA/NWMT.SYSTEM-BURKE/ | NWMT.SYSTEM | BURKE | 115 | All | 132 | 10 | 0 | 10 | 0 | 0 | 122 | 132 | 10 | 0 | 10 | 0 | 0 | 122 |
| N/A | | NC to NWMT.System | NWMT | WS/NWMT/NWMT-NWMT/CANYONFERRY-NWMT.SYSTEM/ | CANYONFERRY | NWMT.SYSTEM | 100 | All | 50 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 0 | 0 | 0 | 0 | 0 | 50 |
| N/A | | NC to NWMT.System | NWMT | WS/NWMT/NWMT-NWMT/GREATFALLS-NWMT.SYSTEM/ | GREATFALLS (NWMT) | NWMT.SYSTEM | 115-100-69 | All | 200 | 254 | 0 | 254 | 0 | 0 | -54 | 200 | 254 | 0 | 254 | 0 | 0 | -54 |
| N/A | | NC to NWMT.System | NWMT | WS/NWMT/WAPA-NWMT/GREATFALLS-NWMT.SYSTEM/ | GREATFALLS (WAPA) | NWMT.SYSTEM | 115-100-69 | All | 200 | 254 | 0 | 254 | 0 | 0 | -54 | 200 | 254 | 0 | 254 | 0 | 0 | -54 |
| N/A | | NE to NWMT.System | NWMT | WS/NWMT/WAPA-NWMT/HILINE EAST-GREATFALLS/ | HILINE EAST | GREATFALLS (NWMT) | 115-100-69 | All | 98 | 0 | 0 | 0 | 0 | 0 | 98 | 98 | 0 | 0 | 0 | 0 | 98 | 98 |
| N/A | | NW to NWMT.System | NWMT | WS/NWMT/WAPA-NWMT/HILINEWEST-GREATFALLS/ | HILINEWEST | GREATFALLS (NWMT) | 115-100-69 | All | 197 | 0 | 0 | 0 | 0 | 0 | 197 | 197 | 0 | 0 | 0 | 0 | 197 | 197 |
| N/A | | NWMT.System to NC | NWMT | WS/NWMT/NWMT-WAPA/NWMT.SYSTEM-GREATFALLS/ | NWMT.SYSTEM | GREATFALLS (WAPA) | 115-100-69 | All | 200 | 53 | 53 | 0 | 0 | 0 | 147 | 200 | 53 | 53 | 0 | 0 | 0 | 147 |

**Figure 18: Northern Tier Transmission Group ATC Information**

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## 19. FERC Order No. 890

In February 2007, FERC amended its regulations and the *pro forma* open access transmission tariff (*pro forma* OATT), adopted in Order Nos. 888 and 889. This action was taken to remedy opportunities for undue discrimination and address deficiencies in the *pro forma* OATT. Increasing the transparency in the rules applicable to planning and use of the transmission system was a key purpose of the rule. Transmission owners are required under FERC Order No. 890 to conduct transmission planning in a transparent and open process. The Final Rule requires that:

- Transmission providers participate in a coordinated, open and transparent planning process on both a local and regional level,
- Each transmission provider's planning process meet the Commission's nine planning principles, which are coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation,
- Each transmission provider must describe its planning process in its tariff,
- FERC will allow regional differences in planning processes.

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## 20. Large Generator Interconnection Procedures (LGIP)

In order for a generator to secure a power purchase agreement from a utility, it must have interconnection agreement with transmission providers. FERC Order 2003 established a *pro forma* LGIP that grants priority on a first come-first served basis. The transmission service providers such as PSCo and Tri-State in Colorado are reporting large queue backlogs. The queue backlog is happening across the country, as well. For example, in a March 2008 report to FERC, the Midwest Independent System Operator estimated that it would take more than forty years to process its backlog under the standard LGIP.

FERC Orders 2003 and 2006 for Generation Interconnection Process specify the following:

- Order 2003 for Large Generators
    - Greater than 20 MW
    - Large Generator Interconnection Process (LGIP)
    - Large Generator Interconnection Agent (LGIA)
    - Apply to all generation technologies

- Order 2006 for Small Generators
    - Less than or equal to 20 MW
    - Small Generator Interconnection Process (LGIP)
    - Small Generator Interconnection Agent (LGIA)
    - Apply to all generation technologies

In March 2008, FERC, after recognizing that Order 2003 has resulted in the unintended consequence of interconnection queues becoming unmanageable, issued an order encouraging Independent System Operators and Regional Transmission Organizations to develop revised interconnection management practices (Docket AD08-2-000). FERC has recently approved several ISO reform initiatives. Typically these involve increased deposits to deter speculative projects, priority for projects that have demonstrated readiness to advance, group studies to support regional network upgrades, and financial commitments to build what has been studied.

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LGI Process is a three steps process, which include Feasibility Study, System Impact Study, and Facilities Study. Each study has its own criteria, cost, and timeline. For example, PSCo's LGI Process is structured as follow:

- Feasibility Study
  - $10,000 deposit
  - Preliminary determination of interconnection and delivery facilities
  - Study Cost is based on actual costs
  - Feasibility Schedule; 6-9 months

- System Impact Study (SIS)
  - $50,000 deposit
  - Proof of Site Control required
  - Transient stability of system is studied
  - Study cost is based on actual costs
  - SIS Schedule: 9-12 months

- Facilities Study
  - $100,000 deposit
  - Detailed engineering design and cost estimates
  - Study cost is based on actual costs
  - Facilities Schedule: 2-4 months
  - Study results become the basis for the Large Generator Interconnection Agreement

PSCo and Tri-State have reported that each company has received a large number of requests with the queue representing more than 23 and 15 GW of new generation, respectively. Tri-State recently has proposed to reform its LGIP by redefining the process and increasing the entry fee of $10,000 to $250,000 for greater than 75 MW projects and $125,000 for less than 75 MW projects. Tri-State has also proposed to reform its interconnection process. Figure 19 shows flow chart of Tri-State's recently proposed LGI Process.

`

PSCo's Interconnection Queue consists of 81 requests (i.e., 52 Wind, 10 Solar, 6 Coal, 12 Gas, and 1 Biomass) with 23.97 GW of new generation capacity.

PSCo also reports the following Active FERC Generation Interconnection Studies (2006-2009):

- Arapahoe – 587 MW
- Boone – 500 MW
- Fort St. Vrain – 300 MW Wind and 256 MW Combined Cycle
- Green Valley – 400 MW Wind
- Hartsel – 100 MW Solar
- Walsenburg – 300 MW Wind
- Comanche – 700 MW Wind
- Keensburg – 250 MW Wind
- Ault – 1600 MW Wind
- Jackson Fuller – 601 MW Wind
- Missile Site – 800 MW Wind and 270 MW Gas
- Lamar – 2,686 MW Wind
- San Luis Valley – 150 MW Wind and 1,730 MW Solar
- Pawnee – 1,170 MW Combined Cycle and 2,820 MW Wind

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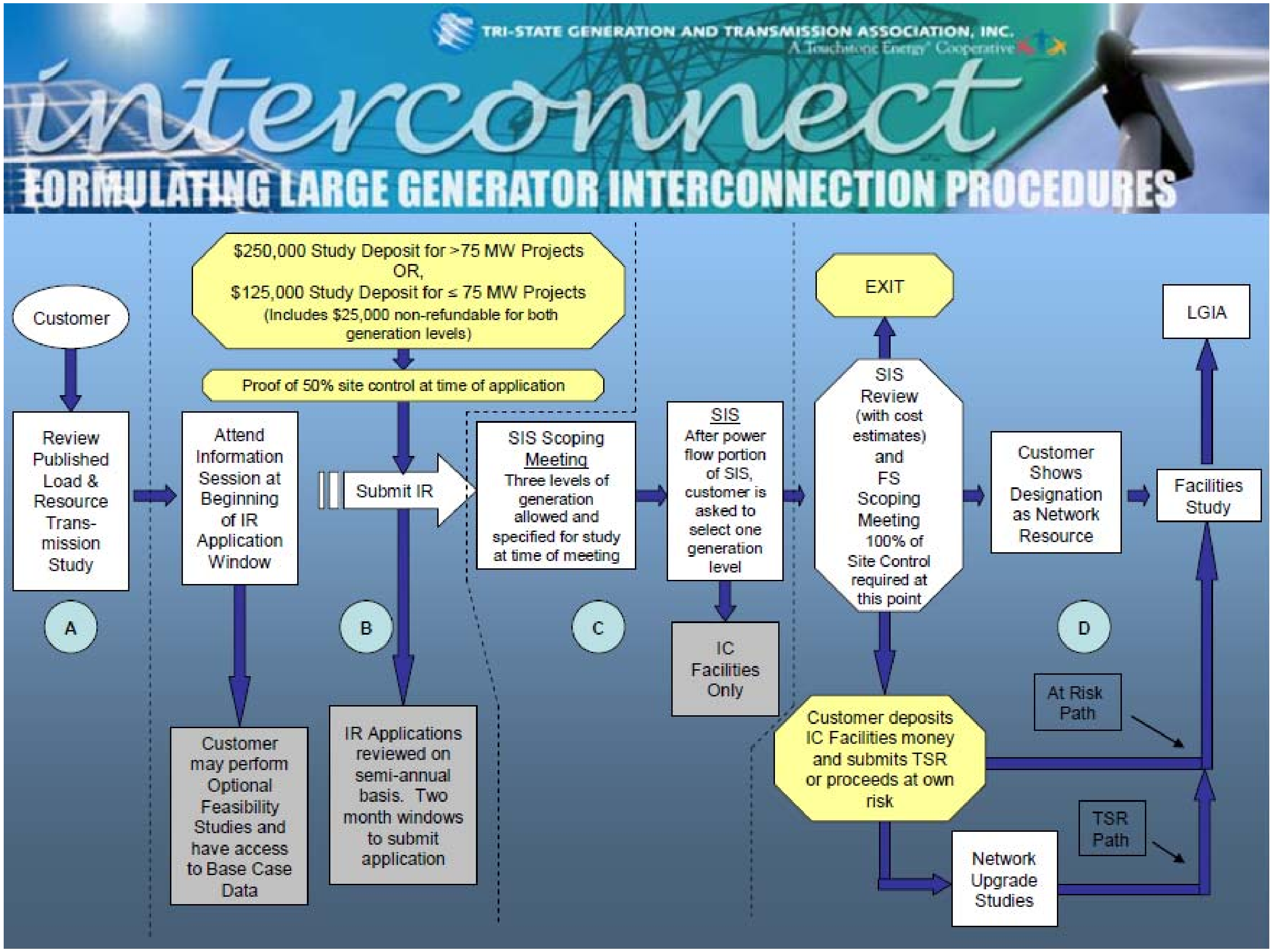


**Figure 19: Tri-State Generation and Transmission Proposed LGI Procedure and costs**

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## CONCLUSION

As it stands today, major utilities in the state; PSCo, Tri-State, and WAPA have limited or no additional transmission capacity to offer for generation interconnection. PSCo's transmission lines is capable of handling up to 1150 MW of additional generation capacity (1650 MW when recent approved Pawnee-Smoky Hill 345 kV line is operational by 2013) which seems to be barely meeting its own 2007 resource plan generation requirements, Tri-State has no transmission capacity to offer other than serving its own members needs, and WAPA has limited capacity, about 250 MW in Colorado to offer other than serving its own needs. Simply put, Colorado is lacking and is need of major transmission improvement investment.

Improving transmission capacity is a key to expanding future development of wind and other variable renewable resources in Colorado. Colorado's Renewable Energy Zones (REZ), which includes the state's richest wind and solar resource areas, are not well served by existing transmission infrastructures. Lack of transmission infrastructure has constrained progress of renewable energy development in Colorado. In response, a Transmission Task Force (TTF) was created in 2006 by the Colorado General Assembly to analyze and report on the transmission infrastructure in Colorado. The TTF concluded that the economic vitality of the state as a whole demands "sufficient transmission capability."

Based upon the Task Force recommendation, the Colorado General Assembly passed Senate Bill 07-100, which was signed into law by the Governor on March 27, 2007. Senate Bill 07-100 recognizes the importance of transmission infrastructure in ensuring the reliability of electric power in Colorado and in providing access to renewable energy facilities. The new law affects Colorado utilities that are subject to rate regulation by the

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Colorado Public Utilities Commission (PUC).[46] It directs the PUC to allow current recovery of the costs of planning, developing and completing the construction or expansion of transmission facilities that have been approved by the PUC through a separate rate adjustment clause that can be changed annually.[47]

Re-evaluation of the proposed 345 kV transmission lines from Lamar-Comanche and Lamar-Missile Site with a double circuit 345 kV lines could increase the transfer capability of proposed lines from 800-1000 MW to 1500-2000 MW from ERZ 3. A joint ownership by Tri-State for the second circuit from Lamar to Comanche could provide shared risk and benefits for joint owners.

Re-evaluation of the proposed transmission line from San Luis Valley Substation to Calumet Substation with a double-circuit 345 kV, may warrant much more benefits than an incremental cost of about $30 million. A double circuit 345 kV transmission line will increase the capacity of the project from 600-1000 MW to 1000 – 1500 MW for solar generation potential in ERZ 4 and 5. In the early years the lines may be underutilized but, as more renewable energy resources are developed in ERZ 4 and 5, the lines will reach their maximum operating limits.

Management of transmission system more efficiently will free up immediate transfer capability on the existing transmission lines. We pointed out the idea of sharing firm transmission capacity for Tri-State use of Burlington diesel operated combustion turbines with other renewable energy developers on a contingent firm contract bases. It appears that this action could free up about 120 MM on the transmission system.

[46] Colorado's second largest transmission owner, Tri-State Generation and Transmission, is not subject to SB07-100.

[47] A separate transmission surcharge now appears on PSCo's customers' electric bills.

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## Issues for Consideration

As we discussed throughout this report, there a few areas that needs to be investigated for possible implementation. The areas of concerns are listed as:

**Larger balancing authority –** PSCo's Cabin Creek pumped storage station is an important tool to maintain compliance with NERC's Control Performance Standards and a potential balancing resource in Colorado. The Mount Elbert pumped storage facility, operated as a base load resource by WAPA, is also a potential balancing resource in Colorado. The prospect of using neighboring resources and moving toward a larger balancing authority, beyond the PSCo system, is a key to more wind penetration in Colorado even with current transmission and operational limitations. This issue should be pursued by all stakeholders.

**Scheduling and Imbalance Charges -** Another step utilities, in particular PSCo, could take to reduce wind integration costs is to "institute sub-hourly schedules" with independent power producers (IPPs) to increase response capability on the PSCo system. The PUC should consider requiring PSCo to investigate and report the possibility of sub-hourly scheduling and the benefits thereof.

**Area Control Error (ACE) -** Sharing ACE diversity through increased cooperation with other utilities provide flexibility for more wind penetration. ACE sharing has been established in the Northern Tier Transmission Group's ACE Diversity Interchange (ADI) program.[48] ADI or ACE Diversity Interchange is the pooling of Area Control Errors (ACE) to take advantage of control error diversity (momentary imbalances of generation and load). The ADI pilot project has been developed by British Columbia Transmission

[48] Available at: http://www.nttg.biz/site/

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Corporation (the Host) and the four control areas (Participants) operated by Idaho Power Company, NorthWestern Energy and PacifiCorp (Eastern and Western control areas).

By pooling their ACEs, the participants have been able to benefit by:

- Reduce control burden on individual control areas;
- Reduce sensitivity to resources with potentially volatile output such as wind projects;
- Reduce unnecessary generator control movement; and,
- Realize improvements in Control Performance Standards.

Colorado utilities should begin experimenting with ADI in a pilot project to indentify the benefits of ADI project by providing more flexibility for more integration.

**Transmission Planning -** Transmission planning is currently coordinated and is underway in Colorado but the time frame is limited to ten years and does not match renewable energy development timetables; these plans address only limited regional market opportunities and could be better coordinated at statewide and regional levels.

**SB07-100 Proposed Transmission Projects -** SB07-100 took a significant next step toward developing the REZs in Colorado by allowing the PUC to grant certificates of public convenience and necessity (CPCN) for new transmission facilities serving GDAs needed by utilities in order to comply with the RES. SB07-100 was also enacted in response to the existing Colorado Coordinated Planning Group's (CCPG) Long Range Transmission Plan proposing "mutually exclusive 'northern' and 'southern' transmission scenarios," put forward in 2006 as a coordinated statewide effort.

One of the topics that needs to be addressed by the PUC in its Transmission Investigatory Docket, which is very important to utilities such as PSCo, is the Commission decision on

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ensuring that the transmission lines built under SB07-100 are built to the right places, i.e., GDAs, and helps encourage generation in the right places at the right prices. Second, the Commission should act to decide on the SB07-100 proposed transmission projects in order to meet the in-service date of the projects.

CCPG should work closely with WestConnect and follow the NTTG's example and WestConnect's recommendation, and make available on the website the ATC Information of major lines for winter and summer and post Available System Impact and Facility Transmission Studies on the web as well. See Figure 19 for examples of NTTG.

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## End Notes


Colorado Public Utilities Commission Transmission Investigatory Docket, *Investigation of Electric Transmission Issues,* Docket No. 08I-227E

Colorado Public Utilities Commission, *Electric Resource Planning*, Docket No 07M-445E

Public Service Company of Colorado, *Colorado Resource Plan 2007,* Docket No. 07A-447E

Tri-State Generation and Transmission, *Electric Resource Planning Rule Compliance Filling*, Docket No. 07M-445E

Colorado Energy Forum, *More Transmission Needed: Colorado's Electric System. And Why It Needs Expanding.* White Paper, August 2007.

DOE, *National Transmission Grid Study,* May 2002.

DOE, *20% Wind Energy by 2030, Increasing Wind Energy's Contribution to U.S. Electricity Supply,* July 2008

EPRI, *Transmission Line Reference Book, 115-138 kV Compact Line Design*

EPRI, *Transmission Line Reference Book, 345 kV and Above*

Wood, A.J. and Bruce Wollenberg, 1996. *Power Generation Operation and Control,* 2nd edition.

Elliott, T.C., 1989. *Standard Handbook of Powerplant Engineering.*

WIRES*, Integrating Locationally-Constrained Resources Into Transmission Systems: A Survey of U.S. Practices*

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# APPENDIX A

## COLORADO EXISTING AND PLANNED GENERATION

## (AS OF 2008)

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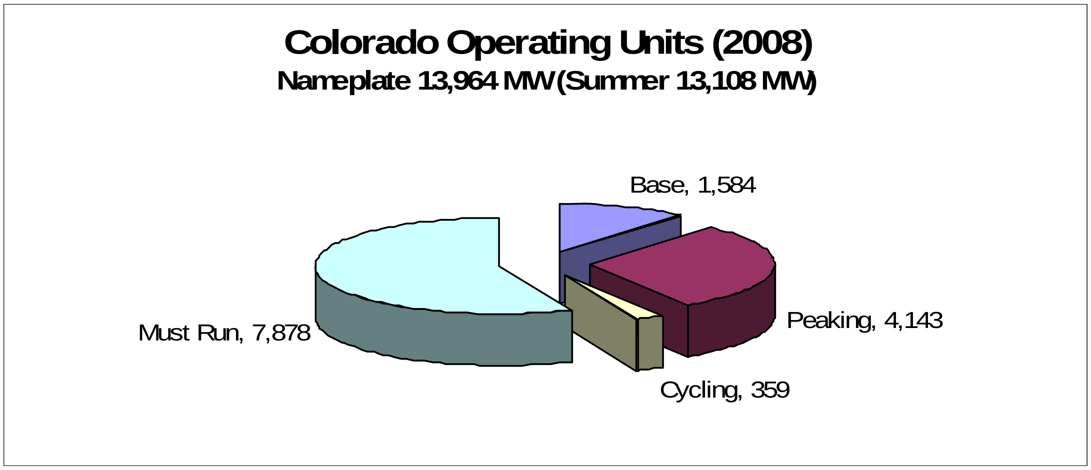


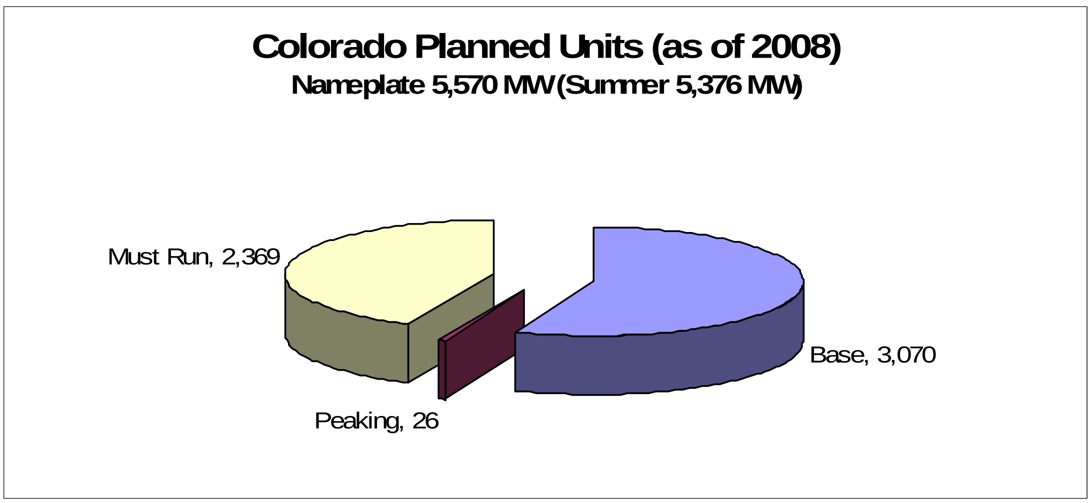


Source: Energy Velocity

| **Operating Codes** | **Prime Mover Codes** |
|---|---|
| AP = App Pending | AB = Atmospheric Fluidized Bed |
| PP = Postponed | CC = Combined Cycle |
| PL = Proposed | GE = Geothermal Steam Turbine |
| UC = Under Const | GT = Combustion Gas Turbine |
| CV = Converted | HY = Hydraulic Turbine, convention |
| CN = Canceled | IC = Internal Combustion Engine |
| OP = Operating | IG = Integrated Gasification Combi |
| OS = Out of Service | NP = Nuclear Reactor, pressurized |
| SB = Standby | PV = Photovoltaic |
| RE = Retired | ST = Steam Turbine |
| | SS = Solar powered steam turbine |
| | WT = Wind Turbine |

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**CYCLING UNITS**

| Plant Name | Owner | First Com | Unit | Tran Zone | Prime | Unit | Nameplate |
|---|---|---|---|---|---|---|---|
| Brush Cogeneration Project Phase 2 | IO | Jan-94 | CC | PSCE | CC | OP | 74 |
| Colorado Power Partners | IO | Oct-90 | CC | PSCE | CC | OP | 88 |
| Zuni | IOU | Jan-48 | 1 | PSCE | ST | OP | 40.2 |
| Zuni | IOU | Jan-54 | 2 | PSCE | ST | OP | 75 |
| George Birdsall | Muni | Mar-57 | 3 | CSU | ST | OP | 23.5 |
| Univ of Colorado | Other | Aug-92 | CC | PSCE | CC | OP | 33 |
| Lamar Plant | Muni | Jan-72 | 4 | PSCE | ST | OP | 25 |
| | | | | | | | **358.7** |

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**MUST RUN UNITS**

| Plant Name | Owner | Online Date | Unit | Tran Zone | Prime | Unit | Nameplate |
|---|---|---|---|---|---|---|---|
| **Operating Units** | | | | | | | |
| Craig (CO) | PSubdiv | Jul-80 | 1 | WAUC | ST | OP | 80.352 |
| Craig (CO) | PSubdiv | Jul-80 | 1 | WAUC | ST | OP | 129.456 |
| Craig (CO) | PSubdiv | Nov-79 | 2 | WAUC | ST | OP | 80.352 |
| Craig (CO) | PSubdiv | Nov-79 | 2 | WAUC | ST | OP | 129.456 |
| Hayden | PSubdiv | Sep-76 | 2 | WAUC | ST | OP | 137.7 |
| Rawhide | PSubdiv | Apr-84 | ST1 | PRPA | ST | OP | 293.6 |
| TCP 272 | Private | Jun-94 | CC1 | PSCE | CC | OP | 164 |
| TCP 272 | Private | Jul-94 | CC2 | PSCE | CC | OP | 222.5 |
| Martin Drake | Muni | Jul-74 | 7 | CSU | ST | OP | 132 |
| Ray D Nixon | Muni | Apr-80 | ST1 | CSU | ST | OP | 207 |
| Arapahoe | IOU | Jan-55 | 4 | PSCE | ST | OP | 112 |
| Cherokee (CO) | IOU | Jan-57 | 1 | PSCE | ST | OP | 125 |
| Cherokee (CO) | IOU | Jan-59 | 2 | PSCE | ST | OP | 125 |
| Cherokee (CO) | IOU | Jan-62 | 3 | PSCE | ST | OP | 170.4 |
| Cherokee (CO) | IOU | Jan-68 | 4 | PSCE | ST | OP | 380.8 |
| Comanche (CO) | IOU | Jan-73 | 1 | PSCE | ST | OP | 382.5 |
| Comanche (CO) | IOU | Jan-75 | 2 | PSCE | ST | OP | 396 |
| Craig (CO) | IOU | Jul-80 | 1 | WAUC | ST | OP | 84.816 |
| Craig (CO) | IOU | Jul-80 | 1 | WAUC | ST | OP | 44.64 |
| Craig (CO) | IOU | Nov-79 | 2 | WAUC | ST | OP | 84.816 |
| Craig (CO) | IOU | Nov-79 | 2 | WAUC | ST | OP | 44.64 |
| Fort St Vrain | IOU | Jul-98 | CC | PSCE | CC | OP | 742.6 |
| Hayden | IOU | Jul-65 | 1 | WAUC | ST | OP | 46.55 |
| Hayden | IOU | Jul-65 | 1 | WAUC | ST | OP | 143.45 |
| Hayden | IOU | Sep-76 | 2 | WAUC | ST | OP | 34.7 |
| Hayden | IOU | Sep-76 | 2 | WAUC | ST | OP | 103 |
| Pawnee | IOU | Nov-81 | 1 | PSCE | ST | OP | 552.3 |
| Valmont | IOU | Jan-64 | 5 | PSCE | ST | OP | 191.7 |
| Arapahoe CT Project | IO | Oct-02 | CC | PSCE | CC | OP | 193.9 |
| Brush IV | IO | May-02 | CC | PSCE | CC | OP | 200 |
| Front Range Power Project | IO | Apr-03 | CC | CSU | CC | OP | 541 |
| Rocky Mountain Energy Center | IO | May-04 | CC | PSCE | CC | OP | 704.9 |
| Thermo Power Electric Inc | IO | Aug-88 | CC | PSCE | CC | OP | 110.8 |
| Craig (CO) | G&TCoop | Jul-80 | 1 | WAUC | ST | OP | 107.136 |
| Craig (CO) | G&TCoop | Nov-79 | 2 | WAUC | ST | OP | 107.136 |
| Craig (CO) | G&TCoop | Oct-84 | 3 | WAUC | ST | OP | 463.4 |
| Rifle Generating Station | G&TCoop | Aug-87 | CC | WAUC | CC | OP | 108.3 |
| | | | | | | | **7877.9** |
| **Planned Units** | | | | | | | |
| Comanche (CO) | DistCoop | Oct-09 | 3 | PSCE | ST | PL | 262.5 |
| Comanche (CO) | IOU | Oct-09 | 3 | PSCE | ST | PL | 487.5 |
| Arapahoe | IOU | May-13 | CC | PSCE | CC | PL | 569 |
| Buick Power Project | IO | Dec-15 | ST | PSCE | ST | PL | 500 |
| Squirrel Creek Power Plant | IO | Jan-11 | CC | PSCE | CC | PL | 550 |
| | | | | | | | **2369** |

## PEAKING UNITS

| Plant Name | Owner | First Com | Unit | Tran Zone | Prime | Unit | Namepla |
|---|---|---|---|---|---|---|---|
| **Operating Units** | | | | | | | |
| Blue Mesa | Federal | Sep-67 | 1 | WAUC | HY | OP | 43.2 |
| Blue Mesa | Federal | Nov-67 | 2 | WAUC | HY | OP | 43.2 |
| Crystal | Federal | Jun-78 | 1 | WAUC | HY | OP | 28 |
| Estes | Federal | Sep-50 | 1 | PSCE | HY | OP | 15 |
| Estes | Federal | Dec-50 | 2 | PSCE | HY | OP | 15 |
| Estes | Federal | Dec-50 | 3 | PSCE | HY | OP | 15 |
| Flatiron | Federal | Jan-54 | 1 | PSCE | HY | OP | 43 |
| Flatiron | Federal | Jan-54 | 2 | PSCE | HY | OP | 43 |
| Flatiron | Federal | May-54 | 3 | PSCE | PS | OP | 8.5 |
| Green Mountain | Federal | May-43 | 1 | WAUC | HY | OP | 13 |
| Green Mountain | Federal | May-43 | 2 | WAUC | HY | OP | 13 |
| Morrow Point | Federal | Dec-70 | 1 | WAUC | HY | OP | 86.6 |
| Morrow Point | Federal | Jan-71 | 2 | WAUC | HY | OP | 86.6 |
| Mount Elbert | Federal | Jun-83 | 1 | PSCE | PS | OP | 100 |
| Mount Elbert | Federal | Feb-84 | 2 | PSCE | PS | OP | 100 |
| Pole Hill | Federal | Jan-54 | 1 | PSCE | HY | OP | 38.2 |
| Towaoc | Federal | May-93 | 1 | WAUC | HY | OP | 11.4 |
| Burlington Co (TRIST) | G&TCoo | Jun-77 | 1 | TSGTECO | GT | OP | 64.7 |
| Burlington Co (TRIST) | G&TCoo | Jul-77 | 2 | TSGTECO | GT | OP | 64.7 |
| Frank R Knutson Generating Station | G&TCoo | May-02 | GT1 | PSCE | GT | OP | 77.1 |
| Frank R Knutson Generating Station | G&TCoo | May-02 | GT2 | PSCE | GT | OP | 77.1 |
| Limon Generating Station | G&TCoo | Jan-02 | GT1 | TSGTECO | GT | OP | 77.1 |
| Limon Generating Station | G&TCoo | Feb-02 | GT2 | TSGTECO | GT | OP | 77.1 |
| Airport Industrial | IO | Jan-02 | E01 | PSCE | IC | OP | 2.5 |
| Airport Industrial | IO | Jan-02 | E02 | PSCE | IC | OP | 2.5 |
| Airport Industrial | IO | Jan-02 | E03 | PSCE | IC | OP | 2.5 |
| Airport Industrial | IO | Jan-02 | E04 | PSCE | IC | OP | 2.5 |
| Blue Spruce Energy Center | IO | Apr-03 | CT01 | PSCE | GT | OP | 234 |
| Blue Spruce Energy Center | IO | Apr-03 | CT02 | PSCE | GT | OP | 234 |
| CSU Pueblo Solar | IO | Jan-09 | PV | CSU | PV | OP | 1 |
| Denver Arapahoe Disposal Site | IO | Jul-08 | IC1 | PSCE | IC | OP | 0.8 |
| Denver Arapahoe Disposal Site | IO | Jul-08 | IC2 | PSCE | IC | OP | 0.8 |
| Denver Arapahoe Disposal Site | IO | Jul-08 | IC3 | PSCE | IC | OP | 0.8 |
| Denver Arapahoe Disposal Site | IO | Jul-08 | IC4 | PSCE | IC | OP | 0.8 |
| Denver Solar Project | IO | Aug-08 | PV1 | PSCE | PV | OP | 2 |
| Dragon Trail | IO | Jun-88 | ICG2 | PSCW | IC | OP | 0.8 |
| Fountain Valley Power Facility | IO | Aug-01 | GT1 | CSU | GT | OP | 38 |
| Fountain Valley Power Facility | IO | Aug-01 | GT2 | CSU | GT | OP | 38 |
| Fountain Valley Power Facility | IO | Aug-01 | GT3 | CSU | GT | OP | 38 |
| Fountain Valley Power Facility | IO | Aug-01 | GT4 | CSU | GT | OP | 38 |
| Fountain Valley Power Facility | IO | Aug-01 | GT5 | CSU | GT | OP | 38 |
| Fountain Valley Power Facility | IO | Aug-01 | GT6 | CSU | GT | OP | 38 |
| Ignacio Gasoline | IO | Dec-84 | G710 | PSCE | ST | OP | 6.1 |

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| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Manchief GS | IO | Jul-00 | UN1 | PSCE | GT | OP | 150 |
| Manchief GS | IO | Jul-00 | UN2 | PSCE | GT | OP | 150 |
| Pueblo | IO | Sep-41 | 5 | WPEC | ST | OP | 7.5 |
| Pueblo | IO | Jul-49 | 6 | WPEC | ST | OP | 15 |
| Pueblo | IO | Feb-64 | IC1 | WPEC | IC | OP | 2 |
| Pueblo | IO | Feb-64 | IC2 | WPEC | IC | OP | 2 |
| Pueblo | IO | Feb-64 | IC3 | WPEC | IC | OP | 2 |
| Pueblo | IO | Feb-64 | IC4 | PSCE | IC | OP | 2 |
| Pueblo | IO | Feb-64 | IC5 | WPEC | IC | OP | 2 |
| Rocky Ford | IO | Jun-64 | IC1 | WAUC | IC | OP | 2 |
| Rocky Ford | IO | Jun-64 | IC2 | WAUC | IC | OP | 2 |
| Rocky Ford | IO | Jun-64 | IC3 | WAUC | IC | OP | 2 |
| Rocky Ford | IO | Jun-64 | IC4 | WAUC | IC | OP | 2 |
| Rocky Ford | IO | Jun-64 | IC5 | WAUC | IC | OP | 2 |
| Valmont Combustion Turbine | IO | Jun-00 | GT1 | PSCE | GT | OP | 71.1 |
| Valmont Combustion Turbine | IO | Jun-01 | GT2 | PSCE | GT | OP | 71.1 |
| 75 St Waste Water | IOU | Feb-87 | 1 | PSCE | GT | OP | 1 |
| Alamosa | IOU | Jan-73 | CT1 | PSCE | GT | OP | 16.5 |
| Alamosa | IOU | Jan-77 | CT2 | PSCE | GT | OP | 16.5 |
| Cabin Creek (CO) | IOU | Jan-67 | A | PSCE | PS | OP | 150 |
| Cabin Creek (CO) | IOU | Jan-67 | B | PSCE | PS | OP | 150 |
| Cherokee (CO) | IOU | Jan-67 | IC1 | PSCE | IC | OP | 2.7 |
| Cherokee (CO) | IOU | Jan-67 | IC2 | PSCE | IC | OP | 2.7 |
| County Line Landfill | IOU | Dec-86 | 1 | PSCE | GT | OP | 1 |
| Fort Lupton | IOU | Jan-72 | 1 | PSCE | GT | OP | 39.2 |
| Fort Lupton | IOU | Jan-72 | 2 | PSCE | GT | OP | 39.2 |
| Fruita | IOU | Jan-73 | 1 | WAUC | GT | OP | 18.6 |
| Ponnequin | IOU | Nov-98 | WT1 | PSCE | WT | OP | 5.2 |
| Ponnequin | IOU | Jun-01 | WT3( | PSCE | WT | OP | 9.9 |
| Ponnequin | IOU | Jun-99 | WT8 | PSCE | WT | OP | 16.5 |
| Shoshone Co | IOU | Jan-09 | A | PSCE | HY | OP | 7.2 |
| Shoshone Co | IOU | Jan-09 | B | WAUC | HY | OP | 7.2 |
| Valmont | IOU | Jan-73 | 6 | PSCE | GT | OP | 45.2 |
| Burlington Co (BURL) | Muni | Jan-60 | 1 | TSGTECO | IC | OP | 1.2 |
| Burlington Co (BURL) | Muni | Jan-65 | 2 | TSGTECO | IC | OP | 2.8 |
| Burlington Co (BURL) | Muni | Jan-69 | 3 | TSGTECO | IC | OP | 2.5 |
| Burlington Co (BURL) | Muni | Jan-51 | 4 | TSGTECO | IC | OP | 1 |
| Center | Muni | Jul-63 | 3 | PSCE | IC | OP | 0.5 |
| Center | Muni | Aug-59 | 5 | PSCE | IC | OP | 1 |
| Delta Co | Muni | Jan-45 | 1 | WAUC | IC | OP | 0.8 |
| Delta Co | Muni | Jan-39 | 2 | WAUC | IC | OP | 0.4 |
| Delta Co | Muni | Jan-38 | 3 | WAUC | IC | OP | 0.1 |
| Delta Co | Muni | Jan-37 | 4 | WAUC | IC | OP | 0.1 |
| Delta Co | Muni | Jan-37 | 5 | WAUC | IC | OP | 0.1 |
| Delta Co | Muni | Jan-49 | 6 | WAUC | IC | OP | 1.2 |

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|---|---|---|---|---|---|---|---|
| Delta Co | Muni | Jan-56 | 7 | WAUC | IC | OP | 2.1 |
| Foothills | Muni | May-85 | 1 | PSCE | HL | OP | 3.1 |
| George Birdsall | Muni | Aug-53 | 1 | CSU | ST | OP | 17.3 |
| George Birdsall | Muni | Mar-54 | 2 | CSU | ST | OP | 18.8 |
| Haxtun | Muni | Jan-47 | 3 | PSCE | IC | OP | 0.27 |
| Holly | Muni | Jan-93 | 4 | PSCE | IC | OP | 0.7 |
| Holly | Muni | Jun-00 | 5 | PSCE | IC | OP | 0.4 |
| Holyoke | Muni | Jan-80 | 1 | PSCE | IC | OP | 0.18 |
| Holyoke | Muni | Jan-80 | 2 | PSCE | IC | OP | 0.3 |
| Holyoke | Muni | Jan-80 | 3 | PSCE | IC | OP | 0.48 |
| Julesburg | Muni | Nov-51 | 1 | PSCE | IC | OP | 0.9 |
| Julesburg | Muni | Jul-49 | 2 | PSCE | IC | OP | 0.9 |
| Julesburg | Muni | Feb-45 | 3 | PSCE | IC | OP | 0.3 |
| Julesburg | Muni | Dec-64 | 4 | PSCE | IC | OP | 1.3 |
| Julesburg | Muni | Apr-46 | 5 | PSCE | IC | OP | 0.3 |
| La Junta | Muni | Jan-39 | 2 | WAUC | IC | OP | 0.7 |
| La Junta | Muni | Jan-39 | 3 | WAUC | IC | OP | 0.4 |
| La Junta | Muni | Jan-42 | 4 | WAUC | IC | OP | 1 |
| La Junta | Muni | Jan-58 | 6 | WAUC | IC | OP | 3 |
| La Junta | Muni | Jan-62 | 7 | PSCE | IC | OP | 3.5 |
| La Junta | Muni | Jan-62 | 8 | PSCE | IC | OP | 3.5 |
| La Junta | Muni | Jan-70 | 9 | PSCE | IC | OP | 5.1 |
| Lamar Plant | Muni | Jan-49 | IC1 | PSCE | IC | OP | 1 |
| Lamar Plant | Muni | Jan-46 | IC2 | PSCE | IC | OP | 1 |
| Lamar Plant | Muni | Feb-04 | T1 T3 | PSCE | WT | OP | 4.5 |
| Lamar Plant | Muni | Mar-04 | WT1 | PSCE | WT | OP | 6 |
| Las Animas (LAMLP) | Muni | Jan-41 | 1 | PSCE | IC | OP | 0.3 |
| Las Animas (LAMLP) | Muni | Jan-41 | 2 | PSCE | IC | OP | 0.3 |
| Las Animas (LAMLP) | Muni | Jan-51 | 4 | PSCE | IC | OP | 1 |
| Las Animas (LAMLP) | Muni | Jan-51 | 5 | PSCE | IC | OP | 1 |
| Las Animas (LAMLP) | Muni | Mar-67 | 6 | PSCE | IC | OP | 3 |
| Metro Wastewater Reclamation | Muni | Apr-85 | 1 | PSCE | IC | OP | 2 |
| Metro Wastewater Reclamation | Muni | Apr-85 | 2 | PSCE | IC | OP | 2 |
| Metro Wastewater Reclamation | Muni | Apr-85 | 3 | PSCE | IC | OP | 2 |
| Metro Wastewater Reclamation | Muni | Apr-85 | 4 | PSCE | IC | OP | 2 |
| Metro Wastewater Reclamation | Muni | Aug-00 | 5 | PSCE | GT | OP | 3.5 |
| Metro Wastewater Reclamation | Muni | Sep-00 | 6 | PSCE | GT | OP | 3.5 |
| Ray D Nixon | Muni | Jul-99 | GT1 | CSU | GT | OP | 35.8 |
| Ray D Nixon | Muni | Jul-99 | GT2 | CSU | GT | OP | 35.8 |
| Secc | Muni | Jan-98 | 1 | CSU | IC | OP | 1.5 |
| Springfield Co | Muni | Jan-65 | 1 | PSCE | IC | OP | 1.2 |
| Springfield Co | Muni | Jan-50 | 2 | PSCE | IC | OP | 0.2 |
| Springfield Co | Muni | Jan-50 | IC4 | PSCE | IC | OP | 0.5 |
| Springfield Co | Muni | Jan-60 | IC5 | PSCE | IC | OP | 0.8 |
| Tesla | Muni | Apr-97 | 1 | CSU | HY | OP | 27.6 |

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|---|---|---|---|---|---|---|---|---|
| Trinidad (CO) | Muni | May-66 | 3 | PSCE | IC | OP | 1.9 |
| Trinidad (CO) | Muni | May-66 | 4 | PSCE | IC | OP | 1.9 |
| Yuma | Muni | Jan-37 | 1 | PSCE | IC | OP | 0.1 |
| Yuma | Muni | Jan-37 | 2 | PSCE | IC | OP | 0.1 |
| Yuma | Muni | Jan-38 | 3 | PSCE | IC | OP | 0.3 |
| Alamosa Photovoltaic Solar Plant | Private | Dec-07 | PV | PSCE | PV | OP | 8.22 |
| Belmar Solar | Private | Oct-08 | PV | PSCE | PV | OP | 1.7 |
| Pagosa SP | Private | Jan-70 | 2 | PSCW | IC | OP | 2.545 |
| Plains End LLC | Private | May-02 | IC1 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC10 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC11 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC12 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC13 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC14 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC15 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC16 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC17 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC18 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC19 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC2 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC20 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC3 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC4 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC5 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC6 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC7 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC8 | PSCE | IC | OP | 7.1 |
| Plains End LLC | Private | May-02 | IC9 | PSCE | IC | OP | 7.1 |
| Snowmass Microhydroelectric Plant | Private | Jul-04 | 1 | WAUC | HL | OP | 0.115 |
| Spindle Hill | Private | Jun-07 | GT1 | PSCE | GT | OP | 157 |
| Spindle Hill | Private | Jun-07 | GT2 | PSCE | GT | OP | 157 |
| SunE SR1 Alamosa WTP | Private | Dec-08 | PV | PSCE | PV | OP | 0.596 |
| SunE SR1 Arvada5 | Private | Dec-08 | PV | PSCE | PV | OP | 0.6 |
| SunE SR1 Broomfield2 | Private | Nov-08 | PV | PSCE | PV | OP | 0.063 |
| SunE SR1 Broomfield4 | Private | Nov-08 | PV | PRPA | PV | OP | 0.2 |
| SunE SR1 Broomfield8 | Private | Nov-08 | PV | PRPA | PV | OP | 0.008 |
| SunE SR1 Nrel | Private | Nov-08 | PV | PSCE | PV | OP | 0.7 |
| Thermo Greeley Inc | Private | Jun-96 | GEN1 | PSCE | GT | OP | 37 |
| Thermo Greeley Inc | Private | Jun-96 | GEN2 | PSCE | GT | OP | 37 |
| Wray School District Wind | Private | Feb-08 | WT | PSCE | WT | OP | 0.9 |
| Lamar Plant | PSubdiv | Feb-01 | 5 | PSCE | GT | OP | 4.2 |
| Lamar Plant | PSubdiv | Feb-04 | T4 | PSCE | WT | OP | 1.5 |
| Lamar Plant | PSubdiv | Mar-04 | WT1 | PSCE | WT | OP | 1.5 |
| Rawhide | PSubdiv | Jun-02 | GT1 | PRPA | GT | OP | 89.3 |
| Rawhide | PSubdiv | Aug-02 | GT2 | PRPA | GT | OP | 89.3 |

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|---|---|---|---|---|---|---|---|
| Rawhide | PSubdiv | Oct-02 | GT3 | PRPA | GT | OP | 89.3 |
| Rawhide | PSubdiv | Jun-04 | GT4 | PRPA | GT | OP | 89.3 |
| Rawhide | PSubdiv | Jun-08 | GT5 | PRPA | GT | OP | 128 |
| Trinidad (CO) | PSubdiv | Jan-99 | 5 | PSCE | IC | OP | 1.8 |
| Trinidad (CO) | PSubdiv | Jan-99 | 6 | PSCE | IC | OP | 1.8 |
| Trinidad (CO) | PSubdiv | Jan-99 | 7 | PSCE | IC | OP | 1.8 |
| American Gypsum Cogeneration | Unknown | Mar-90 | D 1 | PSCW | IC | OP | 1.6 |
| American Gypsum Cogeneration | Unknown | Mar-90 | D 2 | PSCW | IC | OP | 1.6 |
| American Gypsum Cogeneration | Unknown | Mar-90 | T 1 | PSCW | GT | OP | 2.8 |
| American Gypsum Cogeneration | Unknown | Mar-90 | T 2 | PSCW | GT | OP | 3.6 |
| | | | | | | | **4,143.0** |
| **Planned Units** | | | | | | | |
| Denver Arapahoe Disposal Site | IO | Dec-17 | IC5 | PSCE | IC | PL | 3.2 |
| Huerfano Wind | IO | Dec-09 | PV | PSCE | PV | PL | 5 |
| Ormat Highline REG | IO | Dec-09 | ST | PSCE | ST | PL | 4 |
| Plains End II LLC | IO | Dec-09 | IC1 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC10 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC11 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC12 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC13 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC14 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC2 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC3 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC4 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC5 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC6 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC7 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC8 | PSCE | IC | PL | 8.5 |
| Plains End II LLC | IO | Dec-09 | IC9 | PSCE | IC | PL | 8.5 |
| | | | | | | | **131.2** |

## BASELOAD UNITS

| Plant Name | Owner | First Cor | Unit | Tran Zone | Prime | Unit | Nameplate |
|---|---|---|---|---|---|---|---|
| Big Thompson | Federal | Apr-59 | 1 | PSCE | HY | OP | 4.5 |
| Lower Molina | Federal | Dec-62 | 1 | WAUC | HY | OP | 4.8 |
| Marys Lake | Federal | May-51 | 1 | PSCE | HY | OP | 8.1 |
| McPhee | Federal | Dec-92 | 1 | WAUC | HY | OP | 1.2 |
| Upper Molina | Federal | Dec-62 | 1 | WAUC | HY | OP | 8.6 |
| Nucla | G&TCoo | Nov-59 | 1 | WAUC | AB | OP | 11.5 |
| Nucla | G&TCoo | Nov-59 | 2 | WAUC | AB | OP | 11.5 |
| Nucla | G&TCoo | Nov-59 | 3 | WAUC | AB | OP | 11.5 |
| Nucla | G&TCoo | Jan-91 | ST4 | WAUC | AB | OP | 79.3 |
| Cedar Creek Wind Energy | IO | Oct-07 | WT1 250 | PSCE | WT | OP | 273.72 |
| Cedar Creek Wind Energy | IO | Jan-08 | WT251 274 | PSCE | WT | OP | 26.28 |
| Colorado Green Windfarm | IO | Dec-03 | WT1 108 | PSCE | WT | OP | 162 |
| Logan Wind Energy | IO | Aug-07 | WT1 134 | PSCE | WT | OP | 201 |
| Peetz Wind (FPL) | IO | Jan-08 | WT1 133 | PSCE | WT | OP | 199.5 |
| Ridge Crest Wind | IO | Oct-01 | WT1-33 | PSCE | WT | OP | 29.7 |
| Sugarloaf Hydro | IO | Nov-85 | SUG1 | PSCE | HY | OP | 2.5 |
| Trigen Colorado | IO | Sep-76 | GEN1 | PSCE | ST | OP | 7.5 |
| Trigen Colorado | IO | May-77 | GEN2 | PSCE | ST | OP | 7.5 |
| Trigen Colorado | IO | Jun-83 | GEN3 | PSCE | ST | OP | 20 |
| Trigen Colorado | IO | Oct-97 | VBPT | PSCE | ST | OP | 0.4 |
| Twin Buttes Wind Farm | IO | Sep-07 | WT 1-50 | PSCE | WT | OP | 60 |
| W N Clark | IO | Sep-55 | 1 | WPEC | ST | OP | 18.7 |
| W N Clark | IO | Jan-59 | 2 | WPEC | ST | OP | 25 |
| Ames Hydro | IOU | Jan-06 | 1 | WAUC | HY | OP | 3.6 |
| Arapahoe | IOU | Jan-51 | 3 | PSCE | ST | OP | 48 |
| Cameo | IOU | Jan-57 | 1 | WAUC | ST | OP | 22 |
| Cameo | IOU | Jan-60 | 2 | WAUC | ST | OP | 44 |
| Georgetown (CO) | IOU | Jan-06 | 1 | PSCE | HY | OP | 0.7 |
| Georgetown (CO) | IOU | Jan-08 | 2 | PSCE | HY | OP | 0.7 |
| Maxwell Hydro | IOU | Apr-85 | 1 | PSCE | HY | OP | 0.1 |
| Orodell Hydro | IOU | Sep-87 | 1 | PSCE | HY | OP | 0.2 |
| Palisade Co | IOU | Jan-32 | 1 | WAUC | HY | OP | 1.5 |
| Palisade Co | IOU | Jan-32 | 2 | WAUC | HY | OP | 1.5 |
| Salida 1 | IOU | Jan-29 | 1 | PSCE | HY | OP | 0.7 |
| Salida 1 | IOU | Jan-08 | 2 | PSCE | HY | OP | 0.5 |
| Salida 2 | IOU | Jan-08 | 1 | PSCE | HY | OP | 0.6 |
| Sunshine Hydro | IOU | Sep-87 | 1 | PSCE | HY | OP | 0.5 |
| Tacoma | IOU | Jan-06 | 1 | WAUC | HY | OP | 2.2 |
| Tacoma | IOU | Jan-05 | 2 | WAUC | HY | OP | 2.2 |
| Tacoma | IOU | Jan-49 | 3 | WAUC | HY | OP | 3.5 |
| Betasso Hydro | Muni | Dec-87 | 1 | PSCE | HY | OP | 3 |
| Boulder Canyon Hydro | Muni | Sep-11 | 1 | PSCE | HY | OP | 10 |
| Boulder Lakewood Hy (City of) | Muni | Feb-04 | 1 | PSCE | HY | OP | 3.5 |
| Dillon Hydro | Muni | Oct-87 | GEN1 | PSCE | HY | OP | 1.8 |

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|---|---|---|---|---|---|---|---|
| Grand Junction (CO) | Muni | Jan-32 | HY | WAUC | HY | OP | 1.6 |
| Gross Hydro Plant | Muni | Aug-07 | GEN1 | PSCE | HY | OP | 7.8 |
| Hillcrest | Muni | Jun-93 | GEN1 | PSCE | HY | OP | 2 |
| Idylwilde | Muni | Mar-83 | 1 | PRPA | HY | OP | 0.5 |
| Idylwilde | Muni | Mar-83 | 2 | PRPA | HY | OP | 0.5 |
| Longmont | Muni | Jan-12 | 1 | PSCE | HY | OP | 0.3 |
| Longmont | Muni | Jan-12 | 2 | PSCE | HY | OP | 0.3 |
| Manitou | Muni | Jan-39 | 1 | CSU | HY | OP | 2.5 |
| Manitou | Muni | Jan-27 | 2 | CSU | HY | OP | 2.5 |
| Manitou | Muni | Dec-05 | 3 | CSU | HY | OP | 0.55 |
| Martin Drake | Muni | Nov-62 | 5 | CSU | ST | OP | 50 |
| Martin Drake | Muni | Oct-68 | 6 | CSU | ST | OP | 75 |
| North Fork Hydro Co | Muni | Jan-88 | GEN1 | PSCE | HY | OP | 5.5 |
| Redlands Water & Power | Muni | Aug-31 | RED1 | WAUC | HY | OP | 1.4 |
| Roberts Tun | Muni | Jan-80 | NA2 | PSCE | HY | OP | 5.5 |
| Ruedi | Muni | Feb-86 | 1 | WAUC | HY | OP | 5 |
| Ruxton | Muni | Jan-25 | 1 | CSU | HY | OP | 1.2 |
| Silver Lake Hydroelectric | Muni | May-00 | 1 | PSCE | HY | OP | 3.3 |
| Stagecoach Hydro | Muni | Oct-89 | 1 | WAUC | HY | OP | 0.8 |
| Strontia Springs Hydro | Muni | Jul-86 | 1 | PSCE | HY | OP | 1 |
| Taylor Draw Hydro | Muni | Apr-93 | COX1 | WAUC | HY | OP | 2.3 |
| Williams Fork Hydro | Muni | Jul-59 | GEN1 | WAUC | HY | OP | 3 |
| Bridal Veil Falls | Private | Mar-92 | 1 | WAUC | HY | OP | 0.5 |
| Fall River (CO) | Private | Jan-70 | 1 | PSCE | HY | OP | 0.6 |
| Pagosa SP | Private | Jan-70 | 1 | PSCW | HY | OP | 0.2 |
| Spring Canyon Wind Farm | Private | Jan-06 | WT1 40 | PSCE | WT | OP | 60 |
| Twin Buttes Wind Farm | Private | Sep-07 | WT 1-50 | PSCE | WT | OP | 15 |
| Vallecito Hydro | Private | May-89 | GEN1 | TSGTWC( | HY | OP | 0.8 |
| Vallecito Hydro | Private | May-89 | GEN2 | TSGTWC( | HY | OP | 2.5 |
| Vallecito Hydro | Private | May-89 | GEN3 | TSGTWC( | HY | OP | 2.5 |
| Trinidad (CO) | Muni | May-50 | 1 | PSCE | ST | OP | 3.7 |
| | | | | | | | **1,584.0** |
| **Planned Units** | | | | | | | |
| Lamar Plant | PSubdiv | Apr-09 | AB | PSCE | AB | PL | 18 |
| Colorado Green Windfarm | IO | Dec-09 | WT109 158 | PSCE | WT | PL | 75 |
| Huerfano Wind | IO | Dec-09 | WT | PSCE | WT | PL | 50 |
| Huerfano Wind | IO | Dec-09 | WT2 | PSCE | WT | PL | 200 |
| Northern Colorado Wind Energy | IO | Dec-09 | WT1 118 | PSCE | WT | PL | 152 |
| Peetz Wind Energy Center | IO | Dec-10 | WT1 100 | PSCE | WT | PL | 150 |
| Ridge Crest Wind | IO | Jun-10 | WT34 121 | PSCE | WT | PL | 132 |
| Castle Creek Hydroelectric Proje | Muni | Jan-12 | HY1 | WAUC | HY | PL | 0.525 |
| Castle Creek Hydroelectric Proje | Muni | Jan-12 | HY2 | WAUC | HY | PL | 0.525 |
| Cortez Hydro (Co) | Muni | Jan-10 | HY | TSGTWC( | HY | PL | 0.24 |
| Cedar Point Wind | Private | Dec-10 | WT | TSGTECO | WT | PL | 300 |
| Colorado Highlands Wind | Private | Jun-10 | WT1 60 | PSCE | WT | PL | 90 |

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|---|---|---|---|---|---|---|---|
| CSU Green Power Project | Private | Dec-10 | WT | PRPA | WT | PL | 65 |
| CSU Green Power Project | Private | Dec-13 | WT2 | PRPA | WT | PL | 135 |
| Grace Project | Private | Jan-12 | HY | PSCW | HY | PL | 0.14 |
| NECO Wind | Private | Dec-10 | WT1 | TSGTECO | WT | PL | 400 |
| Nevada Ditch Conduit Utilization | Private | Jan-13 | HY1 | PSCE | HY | PL | 0.15 |
| Nevada Ditch Conduit Utilization | Private | Jan-13 | HY2 | PSCE | HY | PL | 0.15 |
| Pole Canyon Wind | Private | Dec-09 | WT1 41 | PSCE | WT | PL | 100 |
| SolarDunes | Private | Jun-12 | SS1 | PSCE | SS | PL | 100 |
| SolarDunes | Private | Jan-14 | SS2 | PSCE | SS | PL | 150 |
| SolarDunes | Private | Jan-14 | SS3 | PSCE | SS | PL | 250 |
| SolarDunes | Private | Jan-14 | SS4 | PSCE | SS | PL | 250 |
| SolarDunes | Private | Jan-14 | SS5 | PSCE | SS | PL | 250 |
| Upper Kiser Creek Hydro | Private | Sep-15 | HY | WAUC | HY | PL | 0.644 |
| Cascade Hydroelectric Plant | Muni | Aug-09 | HY | CSU | HY | PL | 0.85 |
| Greenlight Akron Wind Energy | IO | Jun-09 | WT | PSCE | WT | PL | 200 |
| | | | | | | | **3070.2** |