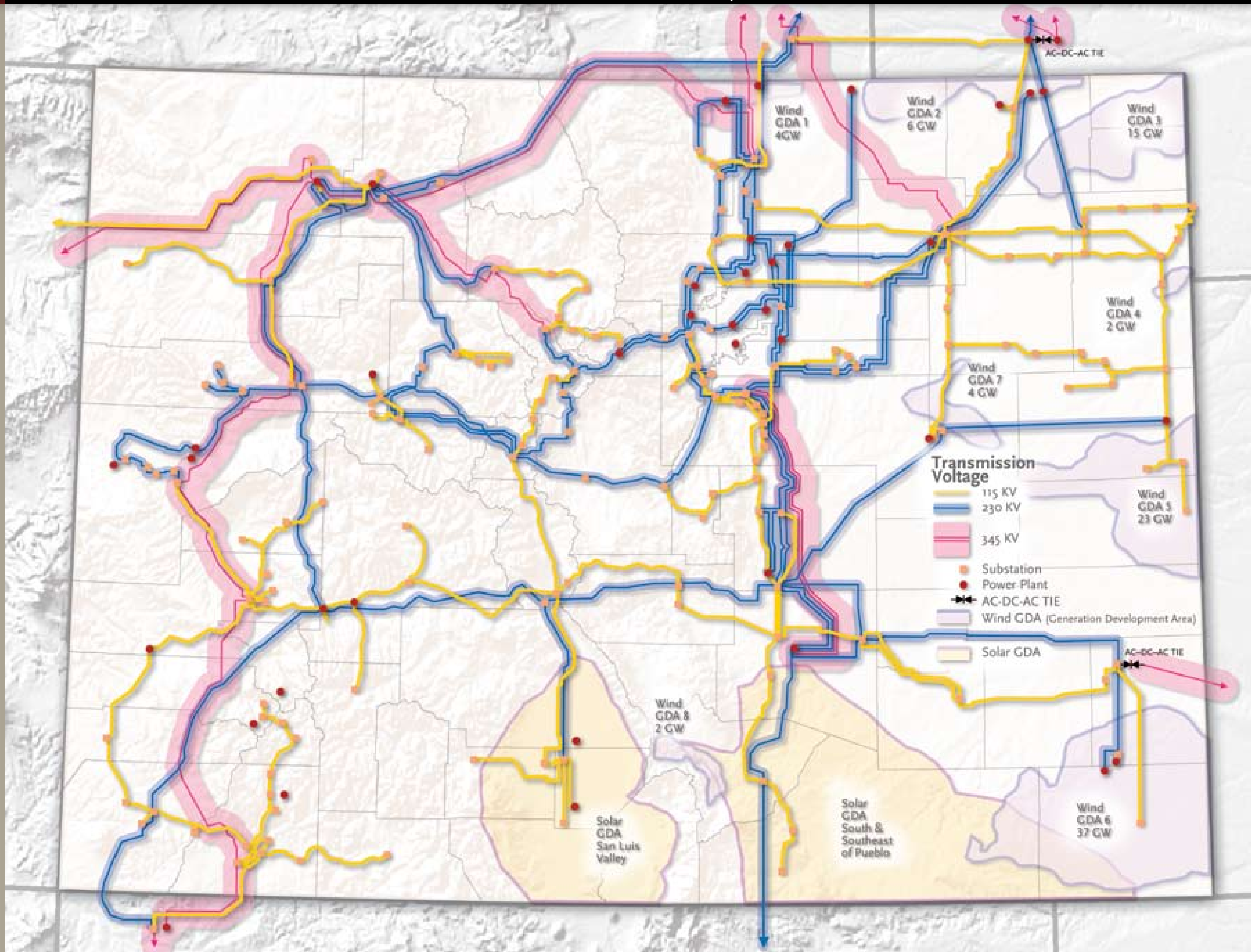
RENEWABLE ENERGY DEVELOPMENT INFRASTRUCTURE

REDI

Connecting Colorado's Renewable Resources to the Markets in a Carbon-Constrained Electricity Sector



A Report of the Colorado Governor's Energy Office

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The Renewable Energy Development Infrastructure (REDI) Report

Connecting Colorado's Renewable Resources to the Markets in a Carbon-Constrained Electricity Sector

Colorado Governor's Energy Office

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Preface, Purpose, and Acknowledgments

Preface

The National Academy of Engineering ranked electric power as the greatest engineering achievement of the 20th Century.[1] Electric power is the lifeblood of our economy. We expect that the next decade will result in dramatic changes in how we produce, transmit, and make productive use of electricity. We offer this report to provide Colorado citizens and other interested stakeholders with information to help bring about positive changes in the electricity sector.

Addressing 600 people at the Third Annual New Energy Economy Conference on October 20, 2009,[2] Colorado Governor Bill Ritter said:

"We are working on a tremendous energy challenge facing us today: transmission — a way to move electrons from clean energy sources to where they're in greatest demand. In Colorado — indeed in much of the country — many of our best renewable energy sources are a long way from the places that require the most electricity. We need a new effort at collaboration to ensure wind power on the Eastern Plains and solar power in the San Luis Valley can travel to the load centers of the Front Range. We must work more closely together and plan with greater foresight to ensure needed transmission for utility-scale renewable power. We must be open to more regional and state-to-state cooperation, and consider new approaches for how transmission is built, and how we pay for it. To this point, my energy office is releasing an important report: The Renewable Energy Development Infrastructure, or REDI, report. The report — the result of a partnership with the DOE — discusses in great detail the need for transmission in our New Energy Economy, the challenges we face and suggestions on how to move the effort forward."

On behalf of the Colorado Governor's Energy Office (GEO), we thank you for your interest in the REDI Project.

The REDI Project includes the REDI Report, the REDI Project's consultants' research ("the Technical Reports") and two REDI videos. The project was designed to expand the discussion regarding Colorado's options on how the state's electricity sector[3] can best plan for its near-term future in a carbon-constrained world. The Technical Reports contain 450 pages of specific results that helped provide factual data, insights, and analysis for the REDI Project. The full output of the REDI Project is accessible on the GEO website: www.colorado.gov/energy go to Electric Utilities, then to the REDI Project.

Purpose

The benchmark goal that drives the report is to achieve a 20 percent reduction in carbon dioxide (CO_2) emissions in Colorado's electricity sector below 2005 levels by 2020. We refer to this as the "20x20 goal." In discussing how to meet this goal, the report concentrates particularly on the role of utility-scale renewable energy and high-voltage transmission[4].

An underlying recognition is that any proposed actions must not interfere with electric system reliability and should minimize financial impacts on customers and utilities. The report also describes the goals of Colorado's New Energy Economy[5] — identified here, in summary, as the integration of energy, environment, and economic policies that leads to an increased quality of life in Colorado.

We recognize that a wide array of options are under constant consideration by professionals in the electric industry, and the regulatory community. Many options are under discussion on this topic, and the costs and benefits of the options are inherently difficult to quantify. Accordingly, this report should not be viewed as a blueprint with specific recommendations for the timing, siting, and sizing of generating plants and high-voltage transmission lines. We convened the project with the goal of supplying information inputs for consideration by the state's electric utilities, legislators, regulators, and others as we work creatively to shape our electricity sector in a carbon-constrained world.

The report addresses various issues that were raised in the *Connecting Colorado's Renewable Resources to the Markets* report, also known as the *SB07-91 Report*.[6] That report was produced by the Senate Bill 2007-91 Renewable Resource Generation Development Areas Task Force and presented to the Colorado General Assembly in 2007. The *SB07-91 Report* provided the Governor, the General Assembly, and the people of Colorado with an assessment of the capability of Colorado's utility-scale renewable resources to contribute electric power in the state from 10 Colorado generation development areas (GDAs) that have the capacity for more than 96,000 megawatts (MW) of wind generation and 26,000 MW of solar generation. The *SB07-91 Report* recognized that only a small fraction of these large capacity opportunities are destined to be developed. As a rough comparison, 13,964 MW of installed nameplate capacity was available in Colorado in 2008.

The legislature did not direct the SB07-91 task force to examine several issues that are addressed in the REDI report. These issues include topics such as transmission, regulation, wildlife, land use, permitting, electricity demand, and the roles that different combinations of supply-side resources, demand-side resources, and transmission can play to meet a CO_2 emissions reduction goal. This report, which expands upon research from a wide array of sources, serves as a sequel to the *SB07-91 Report*.

Reports and research on renewable energy and transmission abound. This report builds on the work of many, including professionals who have dedicated their careers to these topics. A bibliography of information resources is provided, along with many citations to the work of others.

The REDI Project was designed to present baseline information regarding the current status of Colorado's generation and transmission infrastructure. The report discusses proposals to expand the infrastructure, and identifies opportunities to make further improvements in the state's regulatory and policy environment. The report offers a variety of options for consideration as Colorado seeks pathways to meet the 20x20 goal.

The primary goal of the report is to foster broader discussion regarding how the 20x20 goal interacts with electric resource portfolio choices, particularly the expansion of utility-scale renewable energy and the high-voltage transmission infrastructure. The report also is intended to serve as a resource when identifying opportunities stemming from the American Recovery and Reinvestment Act of 2009.

Acknowledgments

The Colorado Governor's Energy Office (GEO) was awarded a grant from the U.S. Department of Energy's (DOE) Office of Electricity Delivery and Energy Reliability to support the REDI Project. The DOE solicitation considered proposals that would lead to development of a minimum of 1,000 MW of new renewable energy capacity in the applicant's state. After receiving the DOE grant, and following a competitive bidding process, GEO retained contractors to conduct research, writing, and project management services. The REDI Project team members included technical consultants from the National Renewable Energy Laboratory (NREL), the University of Colorado-Denver College of Engineering, Navarro-E2MG, R.W. Beck, and WorleyParsons. GEO also contracted with Skeeter Buck for administrative support; David Skiles for GIS work and other deliverables, and John Boak, who designed the report, the full-page maps, charts, and other design work for the report.

The REDI consultants' scopes of work and research tasks were guided by the report authors. The REDI Project greatly appreciates the detailed collection of data, and preparation of analyses produced by the consultants. The REDI consultants' research findings are independent results, however, and their data and conclusions should not be viewed as formal findings by the GEO and the DOE. A primary value of the REDI Project is derived by reading the technical reports, which can be downloaded from the REDI page on GEO's website at www.colorado.gov/energy.

The following reports were prepared by the REDI consultants:

The University of Colorado-Denver (UCD) College of Engineering report was prepared by Dr. Saeed Barhaghi, Engineering Research Professor at the UCD College of Engineering. The 53-page report, *Renewable Energy Development Infrastructure Project: Colorado Climate Action Plan Scenario Analysis For Colorado's Power Sector* focuses on a narrative of the approach taken and the results of the computer modeling of the 20x20 goal. A summary of the modeling work is located in Appendix I of this report.

The Navarro-E2MG report also was prepared by Dr. Saeed Barhaghi. The 102-page report, *Renewable Energy Development Infrastructure Project: Colorado Generation and Transmission: A Baseline Assessment* provides readers with a detailed quantification of Colorado's generation and transmission infrastructure.

The R.W. Beck report was prepared by Bahman Daryanian and his colleagues at R.W. Beck. The 199-page report, *Renewable Energy Development Infrastructure Project: Regulatory and Economic Analysis* provides detailed information about the regulatory, financial, and economic aspects of generation and transmission development.

The WorleyParsons (WP) report was prepared by a team of consultants at WP. The 60-page report, *Renewable Energy Development Infrastructure Project: Environmental, Siting, and Land Use Issues* addresses constraints to renewable energy and transmission developments in the GDAs. It also addresses ecological features, and the land use jurisdictions that affect project permitting and project location.

The National Renewable Energy Laboratory report was prepared by David Hurlbut, NREL Economist. The 30-page report, *Colorado's Prospects for Interstate Commerce in Renewable Energy*, focuses on the potential export market for Colorado's utility-scale renewable energy.

The REDI project team received input from an advisory board composed of: Eugene Camp, representing the Staff of the Colorado Public Utilities Commission; Craig Cox, representing Interwest Energy Alliance; Tom Darin, representing Western Resource Advocates; Rick Gilliam, representing the Solar Alliance; Ethnie Groves Treick, representing Public Service Company of Colorado; Ron Lehr, representing the American Wind Energy Association; Dill Ramsay and Ron Steinbach, representing Tri-State Generation and Transmission Association; and Lee White, representing the Colorado Clean Energy Development Authority. Advisory board members served only in an advisory capacity. The members of the advisory board do not expressly endorse the data or the findings contained in the report and the REDI contractors' technical reports.

The report is a product of the GEO, operating under a contract from the DOE. The authors of the report are Mathew H. Brown, Partner, ConoverBrown, a contractor to the GEO, who served as project manager; David Hurlbut, Economist, National Renewable Energy Laboratory, who contracted with GEO under a Technical Services Agreement; and Morey Wolfson, GEO's Transmission Program Manager, who served as the principal investigator. Corrections to the report should be directed to: morey.wolfson@state.co.us

Acronyms and Abbreviations

ARRA	American Recovery and Reinvestment Act
ATC	Available Transmission Capability
AWEA	American Wind Energy Association
CCPG	Colorado Coordinated Planning Group
COPUC	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CLRTPG	Colorado Long-Range Transmission Planning Group
CREZ	Competitive Renewable Energy Zones
DOE	U.S. Department of Energy
EIA	Energy Information Administration (USDOE)
EPTP	Eastern Plains Transmission Project
ERCOT	Electric Reliability Council of Texas
ERZ	Energy Resource Zone
FERC	Federal Energy Regulatory Commission
GDA	Generation Development Area
GEO	Colorado Governor's Energy Office
HPX	High Plains Express Transmission Project
IOU	Investor-owned utility
ITC	Independent Transmission Company
ISO/RTO	Independent System Operator/ Regional Transmission Organization
MEAN	Municipal Energy Agency of Nebraska
NERC	North American Electricity Reliability Corporation
NREL	National Renewable Energy Laboratory
PSCo	Public Service Company of Colorado
PUC	Colorado Public Utilities Commission
REDI	Renewable Energy Development Infrastructure
SB07-091	Colorado Senate Bill 2007-091 Renewable Resource GDA Task Force
SPP	Southwest Power Pool
SSG-WI	Seams Steering Group of the Western Interconnection
SWAT	Southwest Area Transmission
TSG&T	Tri-State Generation and Transmission Association, Inc.
UCD	University of Colorado at Denver
USDOE	United States Department of Energy
WAPA	Western Area Power Administration
WGA	Western Governors' Association
WP	WorleyParsons

A terminology glossary is provided in Appendix II.

Executive Summary—Major Assumptions and Findings

The report examines how Colorado's electricity sector can reduce its CO_2 emissions by 20 percent by 2020 from its 2005 levels. The report refers to this as the "20x20 goal."

Colorado's electricity sector is moving into an era where it must address a relatively new challenge — carbon dioxide (CO_2) emission reduction. And in so doing, the sector must continue to emphasize system reliability, the need for infrastructure upgrades, and strategic planning to minimize the economic and environmental costs into the future. These, and other, interrelated challenges are the subject of the Colorado Governor's Office's (GEO) 100-page Renewable Energy Development Infrastructure (REDI) Report.

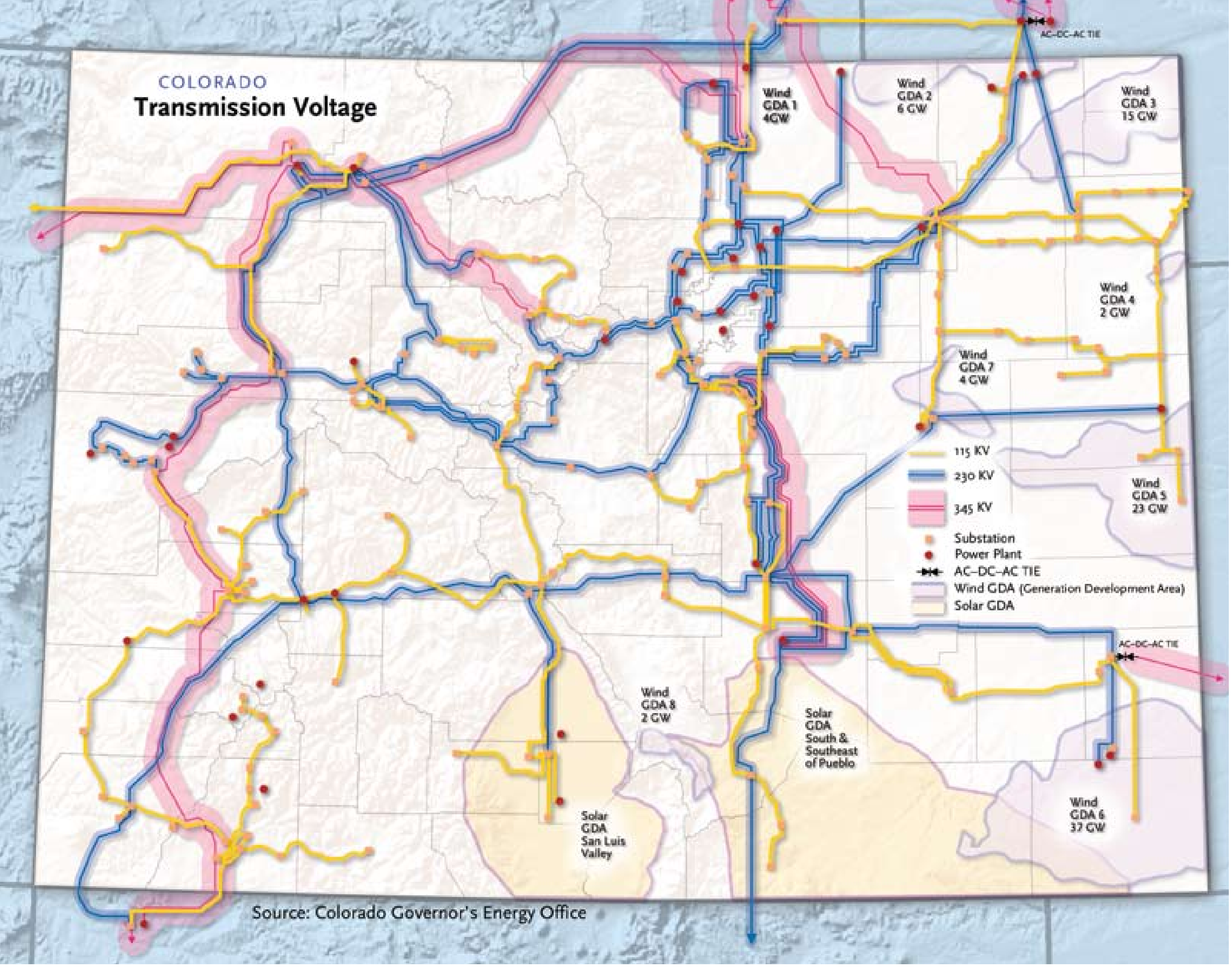
Colorado is fortunate to have some of the most abundant utility-scale renewable resource generation development areas (GDAs) in the nation. To bring that power to the market requires high-voltage transmission infrastructure. Developing Colorado's resources as a means to achieve climate change and economic development opportunity offers an unprecedented opportunity for the state to lead the nation and take full advantage of the New Energy Economy. Leadership in Colorado's electricity sector that successfully addresses the inter-related challenges, including pursuing a CO_2 reduction strategy, will create new jobs, will revitalize many of our rural economies, and will help ensure long-term cost stability for electric customers.

The report examines how Colorado's electricity sector can reduce its CO_2 emissions by 20 percent by 2020 from its 2005 levels — referred to as the "20x20 goal." The report focuses particularly on this question: how can Colorado most effectively address the challenge of building new high-voltage transmission lines to deliver utility-scale renewable power from Colorado's rich renewable resource generation development areas to the markets?

The electricity sector nationally, and in Colorado, is increasing its recognition of and commitment to the need to meet CO_2 reduction goals. As Colorado's electricity sector addresses the 20x20 goal, industry and regulators will also address electric demand growth, water constraints, and the urgent need to upgrade an aging and undersized transmission infrastructure. The report focuses primarily on high-voltage transmission and supply-side electric power options, but it does so within the context of how an appropriate blend of demand-side and supply-side measures can most cost-effectively meet the 20x20 goal.

The map that follows shows Colorado's existing high-voltage transmission infrastructure, defined as 115 kilovolts (kV) and above. Colorado does not have transmission lines with voltages above 345 kV. The map also shows the renewable resource GDAs identified in the *Connecting Colorado's Renewable Resources to the Markets*, also known as the *SB07-91 Report*, where the state's highest concentrations of high-quality wind and solar resources exist. Lines rated at 115 kV are only capable of delivering very modest blocks of power. Higher voltages lines, such as 230, 345, and 500kV lines are far more effective of delivering Colorado's rich renewable resources to the markets. Most of the high-voltage transmission lines in or near the GDAs already are constrained, with little spare transfer capability to accommodate new renewable power development. High-voltage transmission delivering renewable power to the markets will greatly facilitate Colorado's opportunities to reduce CO_2 emissions while expanding the state's economic development.

The REDI Report uses three Colorado electricity sector CO_2 emission scenarios to examine how Colorado might achieve the 20x20 goal. The REDI Project's technical consultant, at the University of Colorado at Denver's (UCD) College of Engineering, developed the quantification of these goals. To conduct the analysis, it was necessary to construct plausible scenarios for the future of Colorado's electricity



Source: Colorado Governor's Energy Office

sector. These scenarios do not constitute formal policy goals, nor are they specific policy recommendations. The analysis of how Colorado's electricity sector can meet the 20x20 goal is summarized in the REDI Report's appendix. A full description of the modeling and assumptions is available in the UCD technical report on the REDI page on the Electric Utilities page of the GEO website (www.colorado.gov/energy).

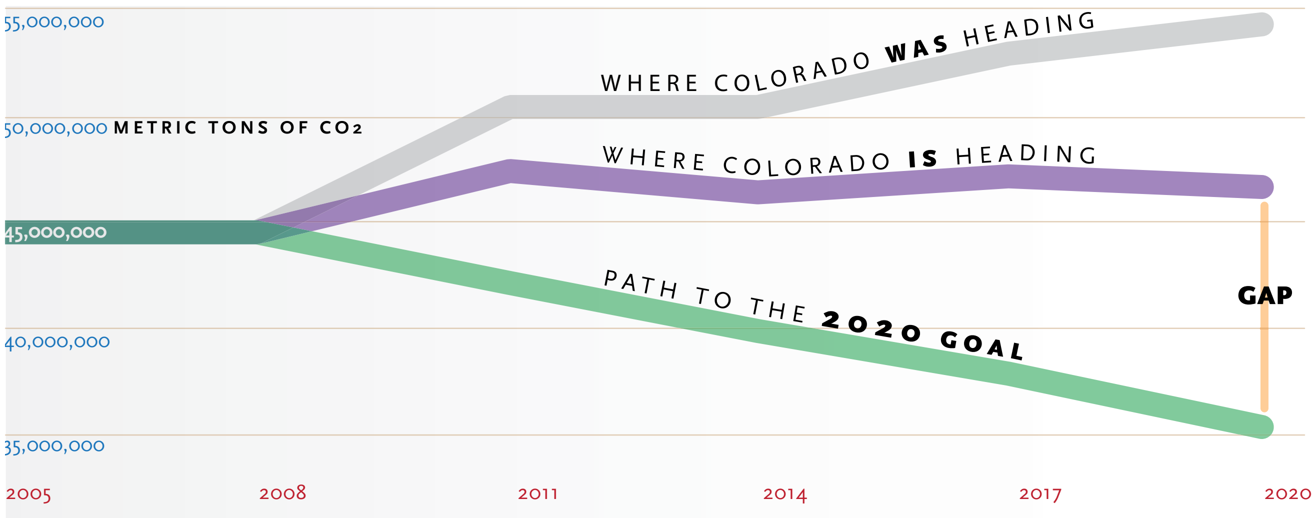
The top line of the following graph indicates the trajectory of CO_2 emissions based on the direction of Colorado's electricity sector before the legislature passed demand-side and renewable energy goals in the past few years. The middle line shows where the Colorado electricity sector is now heading, taking into account current laws and regulatory rules that prescribe renewable energy and energy efficiency outcomes. The bottom line shows the trajectory of CO_2 emissions that Colorado's electricity sector would need to meet to reach the 20x20 goal.

As indicated, Colorado faces a CO_2 emissions gap between where the electricity sector's existing policies will reach by 2020, as compared to the 20x20 goal.

The REDI Report addresses how Colorado's electricity sector could close this gap and concludes that, if the sector is to meet the 20x20 goal, the following steps should be taken:

- Greatly increase investment in demand-side resources (energy efficiency, demand-side management, demand response, and conservation).
- Greatly increase investment in renewable energy development, particularly utility-scale wind and solar generation.
- Accelerate construction of high-voltage electric power transmission to deliver renewable energy from Colorado's renewable resource generation development areas to the state's major load centers.
- Strategically use natural gas-fired power generation to provide needed new power to the grid and to integrate naturally variable renewable resources.
- Consider decreasing the utilization factor of coal-fired generation and/or consider early retirement of the oldest and least efficient of the state's coal-

Colorado Electricity Sector Carbon Dioxide Emissions in Millions of Metric Tons



Source: University of Colorado-Denver College of Engineering

fired generating stations.

Meeting these challenges points to the need not only for continual improvements within the electric power industry, but also to the need for modifications to regulatory and policy structures. Colorado could benefit from even stronger interstate coordination among the multiple players who plan new generation and transmission. The power system currently operates under a smaller balancing authority area than might be desirable for the most advantageous integration of wind and solar power. The current smaller separate balancing authority areas may have the effect of increasing the cost of delivering renewable power to Colorado customers. Without a single regional balancing authority area, Colorado may risk increased costs of transmitting power beyond what such prices might be under more coordinated transmission pricing systems.

Finally, delays associated with siting and permitting of transmission lines will hamper Colorado's utility-scale renewable energy development unless modifications are made to the process.

Although Colorado's electricity sector has made notable strides in recent years in the direction of meeting the 20x20 goal, further steps in that direction are offered by the report. If the sector successfully meets the 20x20 goal, the report indicates that the state's economic development will be bolstered by deployment of clean energy infrastructure, with new jobs stemming from investments in renewable energy manufacturing.

The report suggests that Colorado stakeholders examine:

- The benefits, feasibility and possible procedures for developing a state and regional long-range transmission plan. The objectives of the plan would include traditional electric reliability needs, cost stability, and incorporation of the most cost-effective options to reduce CO_2 emissions.
- The costs and benefits of a regional balancing authority area of which Colorado would be a part. Colorado should strengthen its engagement with neighboring states in relation to governance and operation of the transmission system over a multi-state area.
- The most effective means to secure robust participation from a diverse set of stakeholders to ensure that Colorado's lands, wildlife, scenic, and other natural resources are adequately considered. Stakeholders should also consider whether it is warranted to seek additional guidance regarding the avoidance of sensitive areas.
- Whether a process should be initiated to determine the costs and benefits of a statewide transmission siting authority, to include county commissioners and other key stakeholders.

I. The 20X20 Goal: Reducing Carbon Dioxide in Colorado's Electricity Sector by 20 Percent by 2020 from 2005 CO2 Levels

The modeling results indicate that closing the gap will involve a substantial increase in the use of renewable power and natural gas generation.

This report discusses Colorado's electricity sector and offers information about the challenges it may encounter as it develops plans to reduce carbon dioxide (CO_2) emissions. The baseline analysis underpinning this report stems from what we call the "20x20 goal." The goal is a reduction of CO_2 emissions in Colorado's electricity sector by 20 percent by 2020 from 2005 CO_2 levels. Throughout the report, we pose questions and offer information intended to stimulate further interest aimed at designing sound policies for a less carbon-intensive electricity sector in Colorado.

Baseline information and projections for new electric generation capacity are the results of computer simulations conducted by Dr. Saeed Barhaghi, Engineering Research Professor at the College of Engineering at the University of Colorado at Denver, under a consulting contract with the GEO. The report refers to the modeling work conducted for the project as the "UCD modeling" or "the modeling." The GEO and the DOE did not conduct third-party verification of the modeling results. Accordingly, the report does not formally adopt the findings of the modeling as evidentiary facts. We encourage readers to review the summary of the UCD modeling, located in the appendix of this report. The full technical UCD modeling report is available on the GEO website.[9]

The projections used in the UCD modeling are intended to be a starting point for analysis, recognizing that factors unknown today will undoubtedly affect where Colorado's electricity sector will be in 2020. The REDI project provided guidance to the UCD contractor that the modeling should employ several key assumptions, including, but not limited to the following:

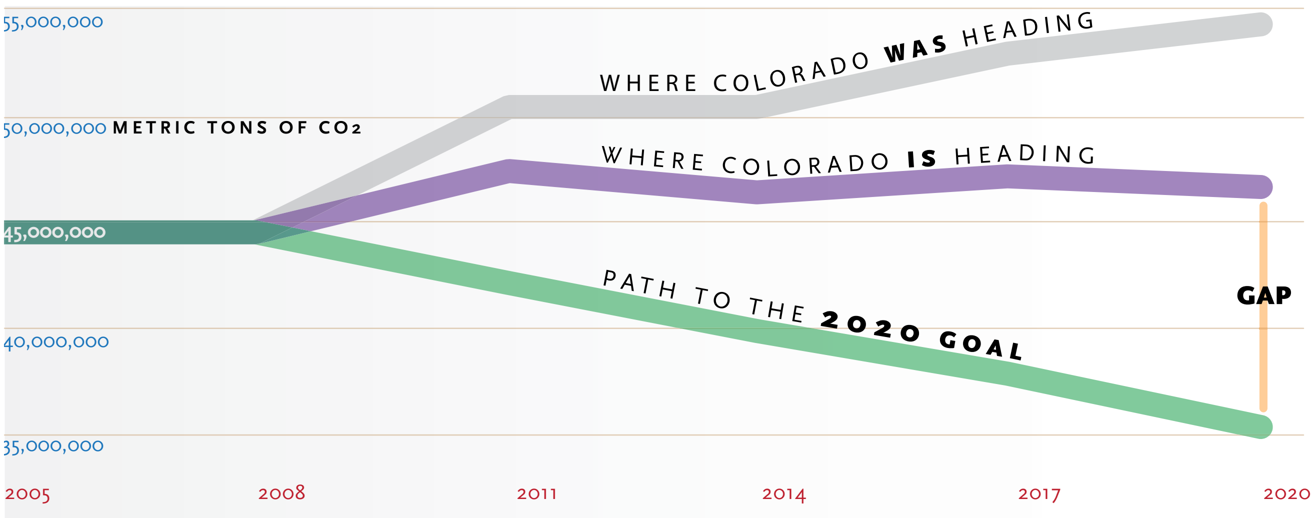
- Do not assume electric generation technologies will go on line by 2020 that are not commercially-viable today.
- Project energy consumption trends based on historical usage data, integrated with current regulatory policies.
- Assume the regulatory and policy structure today represents the maximum that will be accomplished in a "business as usual" scenario. For example, although utilities are not prohibited from accomplishing greater levels of energy efficiency or higher penetrations of renewable energy than are currently required by law, the modeling does not assume that utilities achieve levels of efficiency and renewable energy that are greater than their current regulatory or statutory mandates.
- Use conservative assumptions for fossil fuel prices.
- Assume that an IGCC plant will be built in Colorado before 2020.
- Do not use cost adders that may result from a carbon regulatory structure.

The UCD modeling is based on three scenarios:

The first scenario, illustrated by the top line in the graph on the following page, represents CO_2 emissions stemming from Colorado's 2005 electric generation fleet and the trends for electric demand growth that were evident in 2005. We refer to this line as "Where Colorado Was Heading." Absent policy changes in this scenario, Colorado's electricity sector CO_2 emissions would have escalated from 44 million metric tons per year (MMT/Y) in 2005 to 55 MMT/Y in 2020.

The second scenario, illustrated by the second line, represents expected CO_2 emissions based on current regulatory and statutory requirements. We refer to this line as "Where Colorado Is Heading." This scenario anticipates the minimum generation from renewable energy as required under Colorado's RES, the minimum demand-side management (DSM) policies as required by state law and regulatory decisions, and recently updated forecasts of electric load growth. The modeling calculated that Colorado is currently on a path to reduce annual CO_2

Colorado Electricity Sector Carbon Dioxide Emissions in Millions of Metric Tons



Source: University of Colorado-Denver, College of Engineering

emissions by 7.5 MMT/Y in 2020 from the levels they otherwise would have been if there were no policy changes. These CO2 reductions from the first scenario are a direct result of Colorado's RES and mandated targets for demand-side management (DSM). Credit for these initiatives is widely attributed to unparalleled cooperation and leadership among a variety of entities, including Governor Ritter, the Colorado Legislature, the Public Utilities Commission ("the Commission" or "the PUC"), electric and gas utilities, and engaged Colorado citizens. We note that Public Service Company of Colorado ("PSCo"),[10] Tri-State Generation and Transmission Association ("Tri-State"),[11] and many other Colorado utilities, have adopted CO2 reduction policies that point the way forward to address the topics discussed in this report.

The third scenario, illustrated by the bottom line of the graph, represents the CO2 emissions pathway that the state's electricity sector must reach if it is to attain the 20x20 goal. On the graph, we refer to this as the "Path to the 20x20 Goal." When existing legislative and regulatory measures are taken and projected into the future assuming no new policy changes, electricity sector CO2 reductions will miss the 20x20 target by 11.4 MMT/Y. In other words, the policies currently in force today will take Colorado's electricity sector 40 percent towards the 20x20 reduction goal.

To bridge the remaining gap will require increased demand-side measures, utility-scale renewable energy, new high-voltage transmission, more natural gas generation, and initiatives that address CO2 emissions from the state's oldest and least-efficient fossil plants.

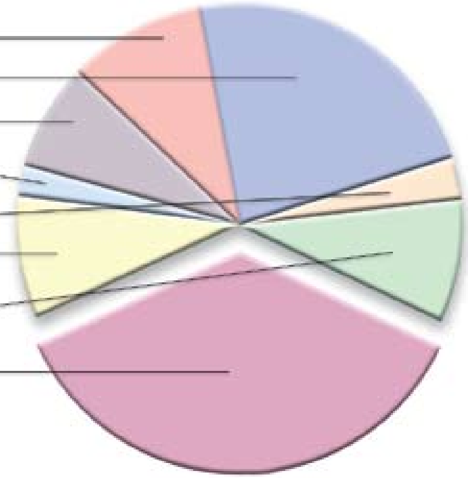
An increase in the necessary levels of high-voltage transmission development, which is a primary focus of this report, is based on projected levels of required generation to meet the 20x20 goal. All estimates of required generation are based on assumptions of the growth in electric power demand. With that approach in mind, the modeling results indicate that closing the gap will involve a substantial increase in the use of renewable power and natural gas generation.

Demand-side measures also will play a critical role in keeping CO2 emissions low. The UCD modeling used an assumption of efficiency policies to keep annual demand growth near the current annual 1.4 percent growth level and also allowed the demand to return to its historical annual growth rate of 2 percent.

PSCo's most recent *Annual Progress Report Regarding Electric Resource Planning* report to the PUC provides detailed energy sales forecasts.[12] The following important statistics are found in the report:

"Residential sales have increased an average of 1.6 percent per year over the past five years. Customer growth is expected to remain at or below levels seen since 2003, averaging 1.2 percent per year. Weather normalized use per customer has increased only 0.1 percent per year over the past five years, and is expected to decline by —0.4 percent per year through 2015, primarily due to new federal standards for lighting and appliance efficiency. As a result, residential sales are forecast to increase only 0.5 percent per year on average through 2015. Commercial and industrial sales are projected to increase at an average annual rate of 1.5 percent through 2015, following average growth of 2.1 percent per year during the past five years. The current recession, including significant impacts on the mining and natural gas industries, resulted in slower growth. During the past five years total retail sales have increased 1.9 percent. Slower residential and commercial and industrial sales growth will result in lower growth of 1.2 percent through 2015."

Colorado CO2 Emissions by Sector



Source: Colorado Climate Action Plan

Aggressive demand-side measures would reduce the growth in demand, resulting in cost-effective savings in the electricity sector. We note that Colorado has made substantial progress recently in energy efficiency. The American Council for an Energy Efficient Economy (ACEEE) reports that Colorado jumped to 16th from 24th among the 50 states in their 2009 State Energy Efficiency Scorecard. [13] We note that the ACEEE's scoring includes factors in addition to utility-sponsored demand side management programs.

For the purposes of this report, however, both generation and efficiency estimates are conservatively calculated based on historical energy use trends and the assumption that utilities will treat current efficiency requirements of state laws and PUC regulations as a ceiling. These factors may well change. The modeling does not assume that these changes will occur, however.

As was determined in the *SB07-091 Report*,[14] the most potentially productive large-scale wind and solar locations are in areas where existing transmission is inadequate to deliver the additional renewable power necessary to meet a 20x20 goal. As a result, Colorado is encouraged to focus increased attention on expanding and upgrading its high-voltage transmission infrastructure. Given the benefit of no fuel costs over a time frame of decades, minimizing the impact on electric customers suggests that utilities should build new high-voltage transmission lines to connect those Colorado areas with the highest concentrations of least-cost renewable potential to the areas of highest electric demand. Achieving these results assumes a continual improvement in the approach to grid planning and operation.

What is the basis for the proposed 20x20 goal in the REDI Report?

The basis for the 20x20 goal is a growing recognition that Colorado's electricity sector is preparing for a carbon-constrained financial, regulatory, and operational environment. Preparing for operating in a carbon-constrained environment has become increasingly important, particularly given recent congressional indicators and activities,[15] at the U.S. Environmental Protection Agency in connection with their endangerment finding,[16] at the Securities and Exchange Commission,[17] and elsewhere. We adopted the 20x20 goal as a baseline condition to conduct an analysis to determine a proposed pathway for Colorado's electricity system portfolio in 2020, recognizing that utilities may exceed existing requirements and that technology will likely undergo substantial changes in cost and availability. These inherently unknown future factors will obviously affect conclusions of our analysis that are grounded in current knowledge.

Accordingly, the REDI Report is analytical rather than visionary. The UCD modeling work assumes that Colorado's utilities will follow historical trends within known legal and regulatory requirements. As policies continue to change and technology advances, the modeling analysis will be outdated, and utilities and others undoubtedly will produce new analyses. As such, the report should be considered a living document aimed at providing information and analysis with the goal of adding to public discussion. We emphasize that the authors do not claim that the proposed pathways are certain, nor do they claim that proposed pathways should be adopted as policy for renewable energy and transmission development in Colorado.

What is Colorado's CO2 emission profile, and how much is attributable to the electricity sector?

In November 2007 Governor Ritter issued the Colorado Climate Action Plan (CAP), noting the importance of achieving climate stability to key Colorado industries, such as agriculture and tourism.[18] A graph on page nine of the CAP is provided on the previous page. It shows that electricity consumption represents 36 percent of Colorado's CO2 levels. Addressing the challenges in Colorado's electricity sector will greatly help meet the broader CAP goals, namely achieving economy-wide CO2 emission reductions.

The REDI Report is analytical rather than visionary. The UCD modeling work assumes that Colorado's utilities will follow historical trends within known legal and regulatory requirements.

Why is transmission so important in how the electric power system operates?
Transmission is a critical element in an interconnected electric power system, which includes generators, transmission lines, substations, distribution lines, and customers. Some have described the North America power system as the greatest engineering accomplishment of the past 100 years. The U.S. electric power industry represents more than $1 trillion in asset value, with 950,000 MW of generating capacity and 200,000 miles of transmission lines. There is no larger collection of assets in any system, except perhaps the petrochemical complex. Colorado is home to dozens of generating stations that equal more than 13,000 MW of capacity, and thousands of miles of transmission power lines of 115 kilovolts and higher voltage. The UCD work conducted for the REDI Project modeled for the base year 2005 included 152 generating units in Colorado with generation capacity of more than 11,200 MW owned by utilities and independent power producers. Since 2005, Colorado has added or will soon add nearly 3,000 MW of new generating capacity to meet the growing demand and a changing resource mix.

Transmission provides a critical link between generators and electric customers. A National Council on Electricity Policy primer on transmission[19] identified four major reasons why transmission is so important. According to the NCEP report, broadly, a strong transmission system:

1) Improves the reliability and security of the electric power system, upon which most of the economy and way of life we enjoy depends,

2) Gives electricity customers flexibility to diversify the mix of fuels that produces their electricity by giving them access to power plants outside of their immediate vicinity,

3) Improves the cost structure of the entire industry by giving low-cost power plants access to high-cost power markets, and

4) Enables competition among power plants by giving more plants access to more markets.

The challenge of operating a robust transmission system is complex, since it is difficult to economically store any significant amount of electricity, and the supply of electricity must always match the demand at any given time. To achieve a consistently high level of reliability and cost effectiveness, the NCEP report described the following major requirements of the electric utility system:

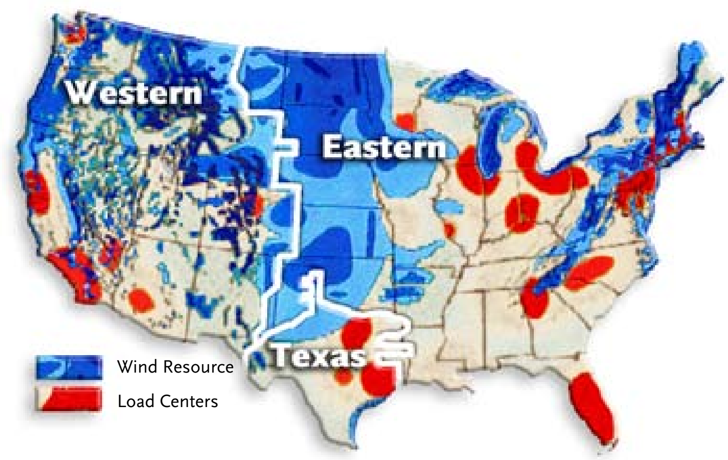
- Balance power generation and demand continuously. As loads come on and off (as weather changes or as a result of, for instance, most electric equipment being turned on at the beginning and end of a work day), power generation must continuously and accurately match that demand. A large mismatch of demand and supply can damage power generation facilities. The mismatch causes, at a minimum, a low voltage condition in some parts of the grid (commonly referred to as brownouts). At a maximum, the mismatch could be so severe that it causes a failure of larger segments of the power grid requiring a rolling blackout if load is intentionally shed for a period of time first in one place, then another.

- Monitor flows over the transmission system to ensure that thermal (heating) limits are not exceeded. Electricity flowing over power distribution and transmission facilities causes those facilities (power lines, substations and the like) to heat as do high ambient air temperatures. When the power lines heat they can sag, and if they make contact with a tree that was not trimmed, for example, it could cause a short circuit. The power system must operate within the constraints of its thermal limits — operators must be sure not to send so much power over the lines that they fail and cause brownouts or cascading blackouts, where loss of load in one area causes adjacent areas to trip and crash.

- Operate the system so that it remains reliable. Transmission system operators are required by federal rules to operate their systems to ensure that if any single line, substation, or generating unit in the system were to fail, the rest of the system could accommodate the loss instantaneously without interruption. Systems must operate to meet frequency targets or face mandatory fines. Meeting this national reliability standard is a way to continually ensure that the transmission system operators can plan for the unexpected loss of a major part of the system and operate so they can maintain grid reliability and service quality for customers.

- Plan, design, and maintain the system to operate reliably. Short-term transmission planning addresses needs — often based on weather and expected power loads — for the following days or week. Long-term planning focuses on a multi-year effort to forecast demand on the transmission and generation system, plan for the mix of generation to supply

Three National Interconnections; Load Centers; Wind Resource



Source: DOE's 20% Wind by 2030 Report

the forecasted loads, and acquire the generators and transmission to bring them to loads. Such long-term planning typically extends for a minimum of 10 years, but often will extend to 15 to 20 years.

When proper safeguards are not in place, a transmission system failure can cascade quickly across multiple states, although physical breakpoints between three separate U.S. interconnections —Eastern, Western, and Texas — isolate such failures to one of the three regions. It is important to note that very few major system failures have occurred during U.S. history. Although they are rare, major failures have occurred, however. The most notable failures were the 1965 blackout in New England and the 2003 blackout in the Midwest and parts of the East Coast and Canada. Minor grid disturbances can become large grid events. On August 10, 1996, for example, a massive voltage collapse caused the largest blackout in the history of the Western power grid.[20] The blackout caused a loss of load of 30,000 MW, and the entire Western Interconnection was broken into five pieces: the amount of power lost was equivalent to 15 cities roughly the size of Denver.

Another critical point relates to the importance of the transmission system for renewable energy. Transmission connects resources to markets ("loads"), and, in general, the best U.S. utility-scale renewable energy resources are far from many population load centers. The map above indicates two important points. First, the nation's wind resources generally are far from the load centers. Second, the nation has three interconnection grids that are not synchronized, and historically could not be.

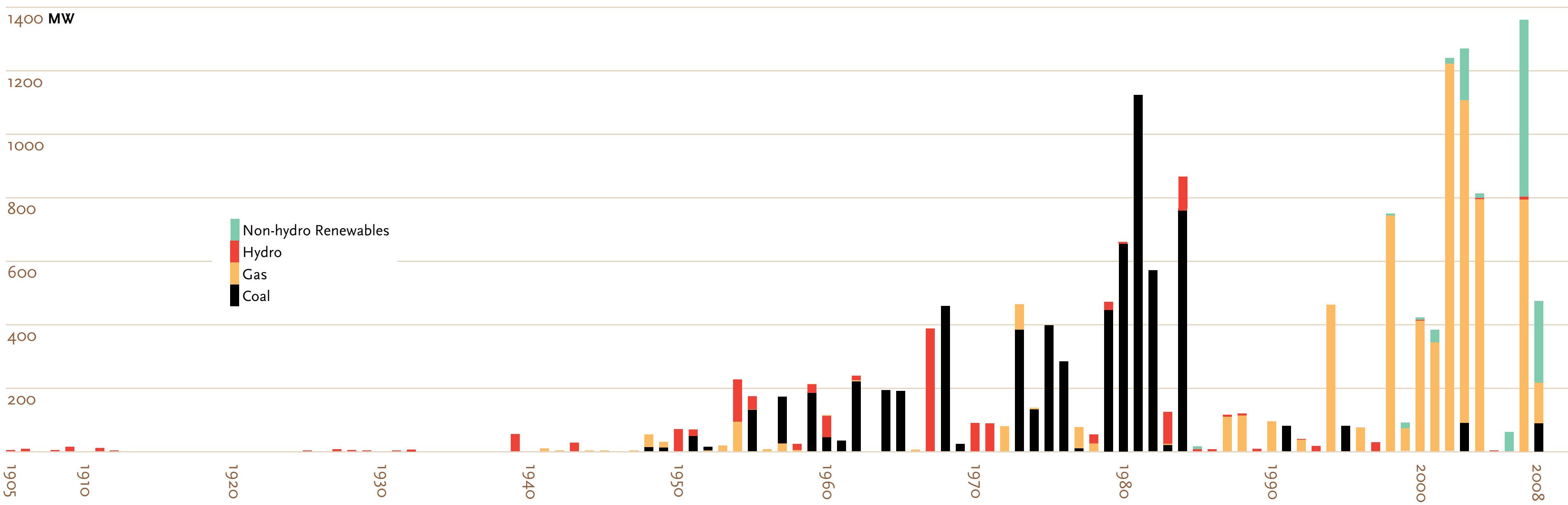
Not shown on the map are six AC-DC-AC ties connecting the Western Interconnection and the Eastern Interconnection in the United States and one additional AC-DC-AC tie in Canada. The other two U.S. ties are Public Service Company of New Mexico's Blackwater, New Mexico tie and the El Paso Electric and Texas-New Mexico Power Company's Artesia, New Mexico tie. PSCo owns the tie in Lamar, Colorado.

Plans have been announced to potentially ease the isolation of the Western, Texas, and Eastern Interconnections. A proposal has been made to develop a 22-square-mile in eastern New Mexico at Clovis, near the Texas border. Clovis was chosen for its proximity to the conjunction of the nation's three power grids. The approximate $1 billion project would allow energy to flow more freely across the nation's three massive power grids. It has the potential to allow more widespread use of renewable energy in the United States. If developed, the Tres Amigas SuperStation[21] would help route energy from isolated wind and solar installations to urban centers and other places that consume the most power. Tres Amigas would build a triangular pathway of underground superconductor pipelines, combined with AC-DC-AC converters to synchronize the flow of power between the interconnections, allowing electricity transfer from grid to grid. Construction could begin in 2011 or 2012, and the hub could be operating in 2013 or 2014. The 3-feet diameter pipelines contain hair-thin ceramic fibers (developed by American Superconductor) that can carry enough electricity to power 2.5 million homes.

What is the history of the Rocky Mountain region's electric generation and fuel type?

The chart above shows the growth in electric generating stations in the Rocky Mountain region from 1905 to the present. Relatively few megawatts of power were added in the region until the 1950s, due to low electric demand and low per capita use by a much smaller population. Following World War II the region experienced a population boom. To keep pace with the demand, major coal and

Generation Vintage in the Rocky Mountain Region by Fuel Type



Source: R.W. Beck/Ventyx Velocity Suite

hydroelectric plants were built during the 1950s. Beginning about 1970 the goal of siting new hydroelectric plants became more challenging, in part due to lack of sites and due to environmental constraints. From the 1970s through the mid-1980s, the major generating additions were coal-fired plants.

Not shown on the graph what was PSCo's Ft. St. Vrain 330 MW high-temperature gas-cooled nuclear reactor. The plant near Greeley, Colo. came on line in the mid-1970s, but was decommissioned in 1989 due to major cost overruns and operational considerations. With the exception of Ft. St. Vrain, no nuclear reactors have been built in the Rocky Mountain region, primarily due to their high costs.

With the advent of gas-fired combustion turbines in the mid-1980s and policies that encouraged competition in the wholesale markets, utilities turned primarily to natural gas for intermediate and peaking resources. Natural gas prices were high in the late 1970s and early 1980s, receded in the mid-1980s, then spiked in the early 2000s. As is evident in the graph, Rocky Mountain region utilities have, for the most part, favored gas-fired generation over the past fifteen years due to its lower comparative capital costs, easier siting, and because major long-distance transmission investments are not necessary.

The graph indicates a marked increase in the number of non-hydro renewables in operation in recent years, most of which have been wind power. Due to concerns about CO_2 and as a result of likely cost-reductions as the technology scales, it is widely expected that the number of solar power plants online in the region during the next decade will substantially increase.

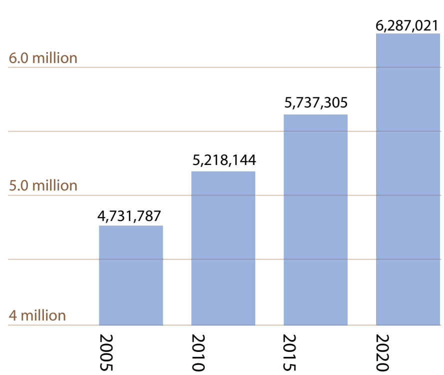
A 750 MW coal-fired generating unit (Comanche 3)[22] in Pueblo, Colo. is expected to come online before the end of 2009 or early 2010. New coal-fired generating stations may be limited due to uncertainties surrounding CO_2 regulation. The generating stations that come online in the next decade will be determined by utility and regulator responses to emerging challenges. These challenges include, but are not limited to financing, permitting, environmental regulation, and available transmission capability.

How does population growth affect the demand for electric power?

Per capita electric consumption is increasing, and, as a result, so are overall demands on both electric generation and transmission. Colorado's population has steadily increased since the end of World War II: the growth rate has fluctuated in concert with population and the economy, but has generally increased during the past 20 years. This population growth translates directly into greater need for electric power and for more aggressive demand-side measures.

Various historical national demographic trends indicate that Colorado's population growth is expected to continue. According to Colorado's State Demography Office, in 1990, 3.3 million people lived in Colorado: by 2009, the number had reached 5.1 million, an increase of more than 55 percent. Assuming an approximate 1.5 percent annual growth rate, the state's population is expected to increase by an additional 21 percent to 6.3 million by 2020. A July 2009 report by the Colorado Water Conservation Board[23] concludes that Colorado's current water use will likely almost triple by 2050 due to a growing population and economy and environmental needs. The growing water requirements form a nexus with strategic electric power questions facing Colorado, since traditional electric generating technologies use large volumes of water.[24] The Water Conservation Board study notes that the state's population is expected to double from 5 million to 10 million between 2010 and 2050.

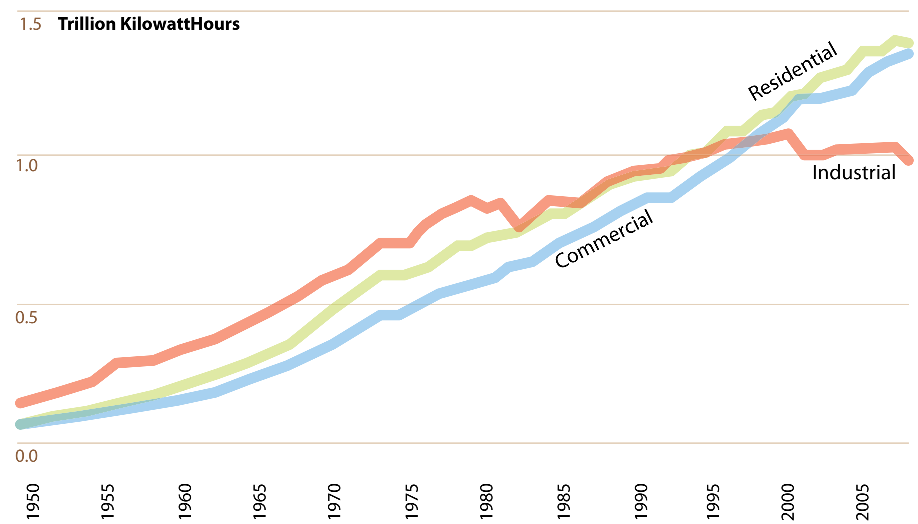
Colorado Preliminary Population Forecast



Source: Colorado Demography Office

Colorado's electric power usage has grown steadily as well. In 1990, total Colorado residential, commercial and industrial electric consumption was almost 31,000 gigawatt-hours (GWh). By 2007, DOE Energy Information Administration data show that consumption had increased by 67 percent, to more than 51,000 GWh. Given the increasing electrification of an energy-hungry digital economy, typified by the growth in plug loads (such as computers, photocopiers in commercial buildings) and the increased penetration of residential air conditioning, the electricity consumption growth outpaced that of the population growth rate. Colorado could be worse off in this regard were it not for the fact that less than one-fifth of the state's households use electricity as their main energy source for home heating.

National Growth in Electric Retail Sales by Sector



Source: DOE Energy Information Administration/Annual Energy Review 2008

According to PSCo, the company's average growth in electric sales from 1997-2008 was 2.6 percent per year. With more ambitious energy efficiency programs, and because of the slow-down in the economy, PSCo has projected the future electric growth rate to be less than it has been historically.[25] Of course, this can change.

Steady national growth in electric consumption is evident in the graph above, produced by the DOE's Energy Information Administration (EIA).[26] The graph indicates retail electric sales in the United States, by sector, from 1949 through 2008.

The graph on the following page provides an historical depiction and future forecast for electric load for the entire state. The forecast was produced in a report entitled *Colorado's Electricity Future a Detailed Look at the State's Electricity Needs and Electricity's Economic Impacts*[27] published in September 2006 by the Colorado Energy Forum, an organization sponsored by Colorado's electric utility industry. That comprehensive study anticipated continued growth in electricity demand during the coming years.

Although the current recession has dampened demand for electricity, it is important to monitor the full economic cycle, which may well include increased demand in future decades. The June 2009 *Short-Term Energy Outlook* from the DOE's Energy Information Administration (EIA)[28] provides this data:

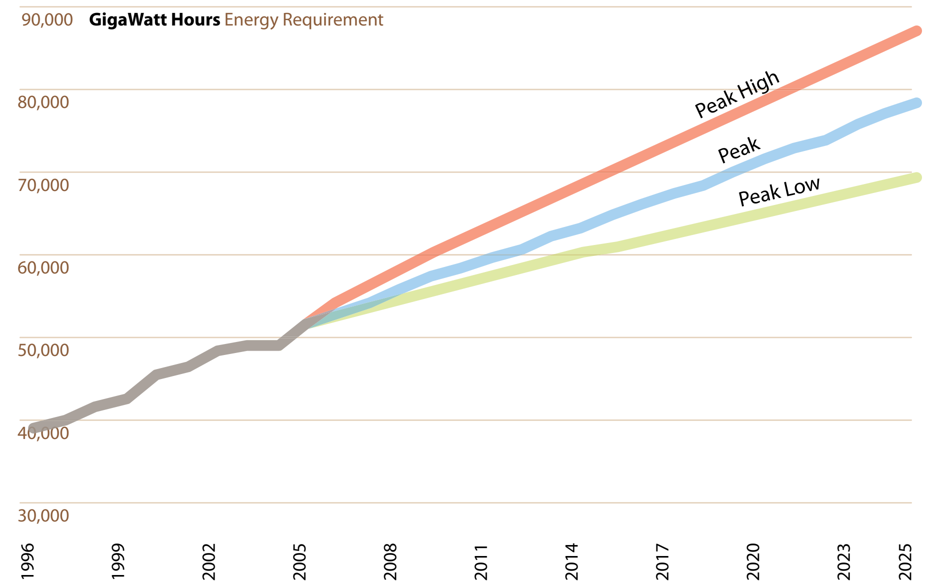
“During the first quarter of 2009, total consumption of electricity fell by an estimated 3 percent compared to the same period last year primarily because of weak industrial consumption. Growth in residential retail sales during the second half of this year is expected to slightly offset continued declines in industrial electricity sales. Total consumption is projected to fall by 1.8 percent for the entire year of 2009 and then rise by 1.2 percent in 2010. Total U.S. electricity consumption fell by 4.4 percent during the first half of the year compared with the same period in 2008, primarily because of the effect of the economic downturn on industrial electricity sales. The expected year-over-year decline in total consumption during the second half of 2009 is smaller, a 2.3 percent decline, as residential sales begin to recover.”

The combination of population growth and the growth in electricity demand suggests a commensurate expansion and balancing of efficiency, generating capacity and transmission. The challenge Colorado faces is to make cost-effective and environmentally responsible decisions, while improving the historically high level of electric reliability in the state. The UCD modeling findings show that new renewable energy development and increased electric transmission capacity — in addition to continued ambitious efforts to reduce demand and increase deployment of demand-side resources — will be critical to meeting new load growth using the most cost-effective, reliable, and environmentally methods. According to REDI’s generation and transmission baseline consultant (Navarro-E2MG),[29] as a result of load growth forecast and the PUC’s Electric Resource Planning process, about 5,570 MW of new capacity is planned to be installed in the next six years: 2,369 MW will be categorized as must run units, 3,070 MW as base units, and 26 MW as peaking units.

Assuming an economic recovery, and if Colorado does not adopt more aggressive statewide electric efficiency goals, the state will face a difficult challenge in its attempt to achieve zero, or near zero, load growth. Several factors potentially stand in the way of efforts to decrease load growth:

- More people are moving into Colorado and require new electric infrastructure to meet their demands.
- Population growth is accompanied by growth in residential electricity consumption due to additional electricity-using equipment.
- The amount of commercial and industrial electricity consumed per dollar of real gross domestic product (GDP) is increasing.
- Energy efficiency in the commercial and industrial sectors has improved since 2003, but not dramatically.

Projected Increase in Peak Hour Generation of Colorado Electric Power, 1996-2025



Source: Colorado Energy Forum

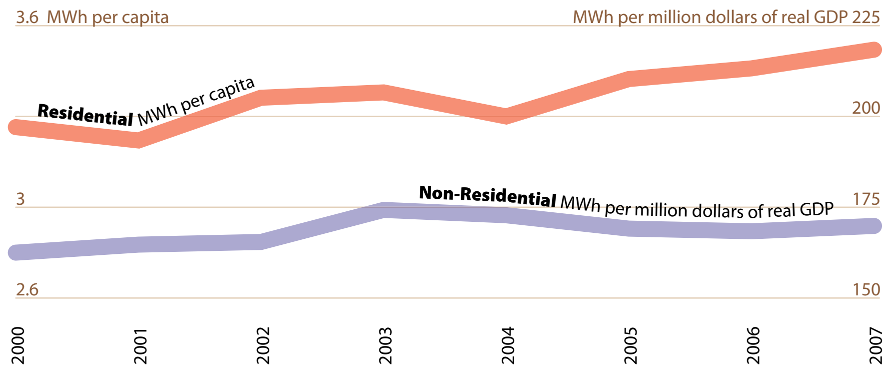
How can demand-side measures help meet the 20x20 goal?

In this report, electric power conservation, energy efficiency, demand-side management, demand response, and distributed generation are defined as “demand-side measures.”

- Conservation refers to behavioral avoidance of unnecessary usage.
- Energy efficiency refers to using less energy to do the same job.
- Demand-side management (DSM) refers to managing the timing and amount of energy use. Those electric customers who avail themselves of utility-sponsored demand-side measures will see lower utility bills.
- Demand response (DR) refers to changing the timing, often using automated controls (or “smart grid” applications), when customers use energy.
- Distributed generation (DG) refers to on site generation, typically owned and run by homeowners or businesses.

Under most circumstances, demand-side measures are cost-effective approaches that will play an increasingly important role in the portfolio of resources Colorado will need to meet its future electric power needs. These demand-side measures are considered an important component of the portfolio that includes a broad mix of supply-side measures that are necessary to meet Colorado’s electric power requirements.

Colorado Residential and Non-Residential Electric Consumption Trends



Source: National Renewable Energy Laboratory

What is distributed generation, and how is that concept emerging in Colorado?

Distributed generation (DG) consists of small-scale electric generators typically located at or near where customers use electricity. Small-scale rooftop or ground-mounted solar photovoltaics (PV) installations are examples. Other technologies such as combined heat and power, distributed wind power, and diesel powered generators also are typically considered to be DG. As of the writing of this report, Colorado has a total of approximately 45 MW of installed PV. By comparison, Colorado had less than 1 MW of installed PV in 2005. An 8.3 MW PV plant installed near Alamosa provides power to PSCo. Several other 1 MW and larger PV projects are installed in Colorado and many more are planned. Should the costs of PV and DG continue to decline and supportive policies substantially expand, DG in Colorado has the potential for exponential growth.

A significant development in the growth of DG in Colorado is now expected, given PSCo's announcement that the company is adding nearly 260 MW of on-site solar power generation to its 2010 Renewable Energy Standard Compliance Plan.[30] The expanded PV goals are part of PSCo's plan to meet Colorado's RES over the next decade: it includes previously announced targets of 700 MW of new wind power and 350 MW of utility-scale solar power plants. Under state renewable energy requirements, PSCo could have complied with the RES with just 85 MW of PV.

Can demand-side measures mitigate or eliminate the need for new central power stations and new transmission?

The answer to this question could be yes, if customer behavior were more dependable, if loads were under greater utility control, or if Colorado experienced no load growth. Colorado's population continues to grow, however, as does the per capita consumption of electric power. The recent economic recession, coupled with new efficiency policies implemented by PUC-regulated investor-owned utilities (IOUs), have reduced load growth in certain utility service territories. Should economic activity in Colorado rebound, the result could include a return of electric demand to the historic growth levels of 2 percent or more per year. With these factors in mind, a pathway going forward would balance rapid deployment of demand-side measures (particularly aimed at lowering expensive peak use); energy conservation across all hours of consumption; and investment in new utility-scale renewable generation, gas-fired generation, and high-voltage transmission resources.

The data shown in the graph above indicate directions for achievable improvements in electricity efficiency: we have the opportunity to use less energy to produce $1 of economic output, and less energy needed to keep Coloradoans comfortable. Doing both not only will reduce CO_2 emissions, but also will support state prosperity and enhance quality of life.

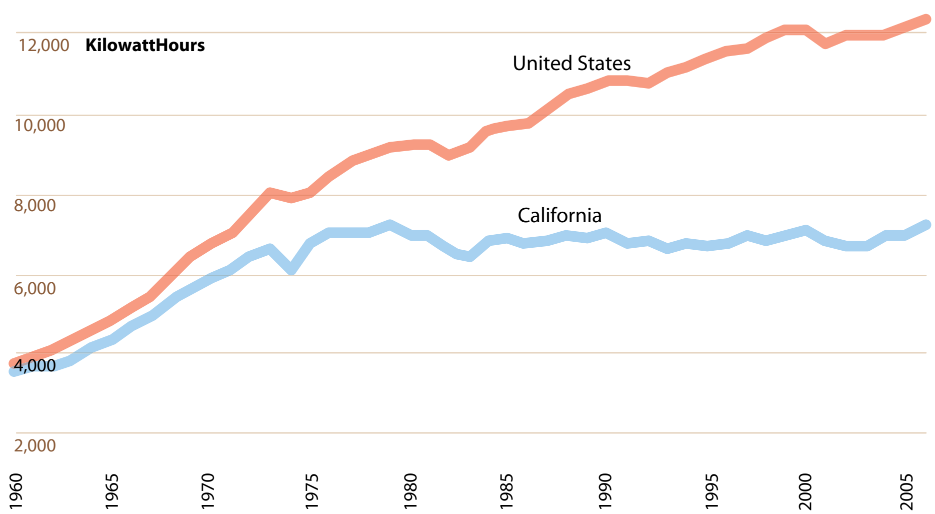
As with all other strategies, some demand-side options are more cost-effective than others. These resources take their place on the customer's side of the meter, requiring financial inputs by the customer, and if determined as policy, by the utility. A report by the Southwest Energy Efficiency Project, *Recent Innovations in Financing for Clean Energy*[31] provides an update on methods being used to help finance many of these measures.

The least expensive of these demand-side measures generally are more cost-effective than the least-expensive new central generation and transmission options because demand-side measures involve less capital cost. Demand-side options typically present less risk because they tend to be small and modular, rather than large and centralized. As utilities evaluate these measures they take into consideration several factors, including operational certainty, durability, and lost revenue.

The recent trend in Colorado toward greater utility emphasis on sponsoring demand-side options is encouraging: far greater emphasis on demand-side solutions will mitigate the need for new supply-side resources, possibly including transmission. New efficiency opportunities also have resulted from advanced federal appliance efficiency standards, and from improved efficiency and reliability of these technologies. A goal of zero percent per capita load growth could be achievable, given a robust investment in demand-side measures, as demonstrated in the chart to the right comparing California to the United States.

For this analysis, the UCD model assumed that Colorado's existing demand-side measure policies will remain unchanged through the year 2020. This is not to assume that no change in existing policies is a preferred scenario. Continued policy changes such as those initiated the Governor, the Colorado General Assembly and regulators in the past several years are to be encouraged.[32] The primary thrust of these demand-side policies, to date, has been applicable to IOUs. New commitments to energy efficiency and renewable energy also have been achieved by innovative approaches taken by the IOUs. We note an important contribution to the topic of demand-side measures has been produced by the Staff of the PUC in a 39-page report, *Energy Efficiency and Colorado Utilities: How Far We've Come; How Far We Need to Go.*[33] It documents the benefits that would be derived as a result of greater commitments and coordination among all Colorado utilities, the PUC, the GEO, and various other stakeholders.

Electricity Sales Per Capita per Year



Source: California Energy Commission

A proposed selection process to help balance these needs is contained in the Electric Power Research Institute's report, *The Power to Reduce CO2 Emissions: The Full Report.*[34] An additional document to help analyze the potential for alternatives to transmission is available in the September 2009 National Council on Electricity Policy report, *Updating the Electric Grid: An Introduction to Non-Transmission Alternatives for Policymakers.*[35] The report provides detailed information regarding five broad policy options including: end-use efficiency, end-user demand response, generation alternatives (including distributed generation), transmission system capability and efficiency improvements within existing corridors, and developing storage technologies, such as batteries and electric and plug-in hybrid electric vehicles.

The September 2009 Northwest Power and Conservation Council report, *Draft 6th Power Plan*[36] found that in each of its power plans, substantial amounts of conservation to be cheaper and more sustainable than many forms of additional electric-generating capability. The *Plan* found enough conservation to be available and cost-effective to meet the load growth of the Northwest region for the next 20 years. The Council states that "If developed aggressively, this conservation, combined with the region's past successful development of energy efficiency could constitute the future equivalent of the regional hydroelectric system; a river of energy efficiency that will complement and protect the regional heritage of a clean and affordable power supply. At the same time, the region cannot stand still in maintaining and improving the reliability of its power system. Investments in additional transmission capability and improved operational agreements are important for the region, both to access growing site-based renewable energy and to better integrate it into the power system."

Today, a vibrant centralized utility system is essential to Colorado's electric reliability. Even under the most ambitious demand-side scenarios, the interconnected system will continue to help meet the needs of a growing decentralized paradigm. A harmonious combination of demand-side resources and a careful selection of supply-sources will most effectively meet the state's energy, economic, and environmental goals.

How can utility-scale renewable resources help meet the 20x20 goal?

A low-carbon Colorado electricity sector will require changing the balance of fuels in the state's electric generation portfolio. The change will result in use of fewer high-carbon fuels such as coal, a greater fraction of lower-carbon fuels such as natural gas to displace the higher carbon generation, and more zero or near-zero carbon sources — including demand-side measures, wind, solar, geothermal, and hydropower. Even if existing energy efficiency goals are met, a substantial increase in utility-scale renewable generation and natural gas generation will be required, as will new high-voltage transmission.

As of September 2009, PSCo receives output generated by 1,232 MW of nameplate capacity from 10 wind farms located within Colorado and 25 MW from one wind farm in Wyoming.

The utility-scale renewable industry has grown considerably in the past few years, and is well-positioned to grow even more. Colorado has much to gain in the process. According to Colorado-based Interwest Energy Alliance, a trade and advocacy group, Colorado currently has 12 wind farms, most of which have power purchase agreements with PSCo. Together, these wind turbines produce enough power for approximately 400,000 homes. The Interwest Energy Alliance reports that more than 30 wind farms are installed in various sizes in Arizona, Wyoming, New Mexico, Utah, and Colorado.

Colorado's utility-scale renewable energy industry is robust, as evidenced by the industry's response to a request for proposal (RFP) issued by PSCo's 2009 All Source Solicitation: PSCo received 49 wind bids totaling 10,800 MW; 28 bids for solar (photovoltaics and thermal) totaling 2,150 MW; eight bids for solar (PV and thermal with storage or gas backup) totaling 1,250 MW; and three non-solar renewable energy bids totaling 1,150 MW. Most of these bids came from projects located in Colorado. Under its most recent resource plan, PSCo will add nearly 1,000 MW of wind and solar to its system, and it will retire older coal-fired power plants (Units 1 and 2 at the Cameo Station near Grand Junction by the end of 2010, and Units 3 and 4 at the Arapahoe Station in south Denver by 2014), totaling 229 MW.

As of September 2009, PSCo receives output generated by 1,232 MW of nameplate capacity from 10 wind farms located within Colorado and 25 MW from one wind farm in Wyoming. PSCo operates on the basis of regulatory and corporate commitments that continue to increase the company's renewable energy purchases as economically and operationally feasible. Although rural electric cooperatives, aggregated for generation purposes primarily by Tri-State, and municipal utilities have similar, but smaller renewable energy standard obligations, they, too, see opportunities to expand their commitment to develop more utility-scale renewable energy.

Further evidence of Colorado's continued utility-scale renewable energy growth was the July 6, 2009 announcement by Tri-State of its plans to purchase the output of 51 MW of wind power from Duke Energy Generation Services. This agreement was made possible because Tri-State had a limited amount of capacity on its constrained transmission system. The wind farm, to be built near Burlington, Colo., will supply enough electricity to supply 14,000 households served by distribution co-ops within the Tri-State network. Duke Energy will build the project and sell the power to Tri-State for 20 years. The project, consisting of 34 turbines on 6,000 acres, is expected to be completed by the end of 2010. About 150 people will be employed to build the project and four to eight full-time technicians will maintain it. Duke Energy reported that costs were "north of $100 million."

The *SB07-91 Report* identified Colorado GDAs that have the best potential for producing low-cost wind power and central-station solar power. Large-scale wind plants have proven to be commercially and economically viable. Large-scale wind developments on the Colorado grid act as a hedge against high natural gas prices. Photovoltaic plants show steadily decreasing costs that could potentially bring them to "grid parity" costs in the next decade. These plants are included in the state's renewable energy standard, established to enable further cost decreases through more widespread deployment. Photovoltaics and concentrated solar power (CSP) plants can also serve as a hedge against high natural gas prices. In addition, strategically located smaller renewable power plants, although they have higher capital costs than larger ones, could reinforce local reliability, reduce or delay transmission upgrades, and help diversify the system. This would be especially applicable in areas on Colorado's Western Slope where building new transmission is more challenging.

How can natural gas-fired generating plants help meet the 20x20 goal?

According to the Independent Petroleum Association of the Mountain States, Colorado is the sixth largest producer of natural gas in the United States. Seven of the nation's 100 largest natural gas fields are found in Colorado. Colorado is responsible for more than one-fourth of all coalbed methane produced in the United States. Coalbed methane output accounts for about one-half of Colorado's natural gas production.

On many occasions Governor Ritter has noted that he considers natural gas to be an essential and permanent part of the New Energy Economy. This report recognizes that natural gas is not a bridge fuel, and it is not a transition fuel. Natural gas is a mission-critical fuel when considering reductions in CO_2 emissions and the need to integrate utility-scale renewable energy. Natural gas-fired electric generation has the important attribute of being a flexible resource that emits half

Natural gas is not a bridge fuel, and it is not a transition fuel. Natural gas is a mission-critical fuel when considering reductions in CO_2 emissions and the need to integrate utility-scale renewable energy.

as much CO_2 per MWH as coal-fired generation.[37] The North American Electric Reliability Corporation forecasts natural gas generation capacity will increase by 38% over the next decade, while coal-fired generation, which currently provides about half of the power in the U.S., will only grow by 6%.

A recent indicator of the increase in gas-fired generation in Colorado is the announcement by a Black Hills Energy subsidiary to build a 200 MW plant with the potential for a minimum of 100 MW expansion of natural-gas fired generation beyond that. The power will be distributed to nearly 100,000 of Black Hills Energy's utility customers in its service territory, which encompasses Pueblo, Canon City, and Rocky Ford, Colorado.

In Minnesota, Xcel Energy has completed a $1 billion voluntary project—the Metro Emissions Reduction Project—which included conversion of two of its older pulverized coal generation plants to gas combined-cycle technology. As a result, sulfur dioxide and nitrous oxide emissions from the plants were reduced by more than 95 percent, and CO_2 emissions were cut by roughly 40 percent.

Electric utilities rely on gas-fired generation to reach a moment-to-moment balance between system demand and total system generation, which is essential to preventing system failure. Coal-fired generation (and nuclear plants elsewhere in the nation) lacks this ability to quickly increase or decrease production. Although wind and solar output can change quickly, modern gas-fired generating plants are flexible enough to manage such changes and maintain overall system reliability.

Integrating more renewable power reliably and cost effectively involves various approaches. It is important to re-examine how natural gas is dispatched, transported, and stored: how gas-fired generating units are specified for new equipment to be added; and how both new units and existing generators are dispatched. The Colorado electricity sector has a need for more output from natural gas plants. The UCD modeling quantifies the need for a substantial increase in natural gas generation on Colorado's electric power system to provide injection of new power to meet load growth and to provide necessary firming and integration of renewable resource generation.

State-of-the-art forecasting can enable efficient co-scheduling of wind, solar and natural gas power. These forecasting techniques will make it possible to maximize every megawatt of renewable capacity, minimize the effects on reliability, and reduce costs to electric customers. A strong synergy between variable renewable resources and dispatchable natural gas plants is described in greater detail in this report.

What is the role of coal-fired generation regarding the 20x20 goal?

Coal-fired generation has played a major role in providing affordable, reliable power to Colorado's electric customers for many years. Coal will likely will have a continued, but perhaps diminishing, role as an important source of baseload power generation. Coal-fired plants account for about seven-tenths of the state's electric power generation.

Colorado produces coal from both underground and surface mines, primarily in Colorado's western basins. Large quantities of coal are shipped in and out of the state by rail. Colorado's major coal mining companies are the Foidel Creek Mine/Twentymile Coal Company, Elk Creek Mine/Oxbow Mining, Colowyo Mine/Colowyo Coal Company, and West Elk Mine/Mountain Coal Company. Colorado uses about one-fourth of its coal output and transports the remainder to markets throughout the United States. Colorado brings in large quantities of coal by rail, primarily from the Powder River Basin in Wyoming, to supplement local production for Colorado electric power generation.

The UCD modeling made the conservative assumption that all of Colorado's existing coal-fired generating stations would continue to generate electricity through 2020 before being retired in later years. The exception to this assumption is the planned retirement of 229 MW of PSCo-owned generation, approved by the PUC. The UCD modeling assumes that 750 MW of new coal-fired generation from the third unit at the Comanche power plant in Pueblo would come online in late 2009.

The modeling also assumes that a new coal-fired integrated gasification combined cycle (IGCC) plant would come online in 2016. This assumption is based on PSCo's filing in the company's November 2007 Electric Resource Plan (ERP). However, PSCo has not yet made a final decision to build an IGCC and no application to build it has been filed with the PUC. PSCo has modeled an IGCC plant as a placeholder in 2016, which is beyond the resource acquisition period in the November 2007 plan. In addition, more suggested coal retirements may be made to the PUC in the next ERP cycle to be filed by October 2010, and it is possible that the 2016 IGCC plant may be delayed.

Should Colorado decide to implement the 20x20 goal, it is unlikely that new coal-fired generation would be added to the energy mix unless the plants contain major advances in carbon capture and storage.

General Electric and British Petroleum recently announced a plan to jointly build a 250 MW IGCC plant designed to capture and store 90 percent of CO_2 emissions. The plant will be located near Bakersfield, California. It is designed to reduce sulfur dioxide, nitrous oxide, mercury and particulates, and will operate with 30 percent less water needs than conventional coal plants.

Should Colorado decide to implement the 20x20 goal, it is unlikely that new coal-fired generation would be added to the energy mix unless the plants contain major advances in carbon capture and storage (CCS).[38] Although often halting and fragmented, CCS efforts have been under way for some time. However, because the technology is not yet commercially available, and because the costs remain high, CCS is not a part of the UCD modeling. CCS could, however, be a "game changer," and is addressed later in this report.

In one modeling run, the UCD research analyzed the effects of de-rating the output of coal-fired generation to determine the impact on reducing CO_2 emissions. For purposes of this analysis, the modeling assumed the typical utilization rate of coal-fired generation in the Rocky Mountain region at 85 percent. The model ran one scenario in which the same coal units in Colorado's fleet operate at a 65 percent utilization rate by 2020.

Although another modeling approach could have been constructed that would assume early retirements of specific coal units, the UCD modeling did not do so. The modeling also did not include co-firing coal-fired generating stations, which is another option to reduce CO_2 emissions. Sufficient resources were not available in the REDI Project to model these two options. Studies of these two topics are warranted to supplement the modeling conducted by UCD on reducing the utilization rate of coal-fired generation.

The UCD modeling concludes that the largest portion of the state's electric energy requirements and capacity needs to 2020 will be met by an integrated combination of utility-scale renewable generation, increased natural gas generation, and derating of coal-fired generating stations.

What policy and other steps have been taken in the past few years to move toward the 20x20 goal?

Many positive steps are apparent, particularly with regard to utility-scale renewable energy and high-voltage transmission development policies. In addition, significant policies have been enacted and practices have been implemented to encourage greater use of demand-side resources. A narrative of the policy developments surrounding demand-side resources is contained in the *SB07-91 Report* and the PUC Staff report on energy efficiency referenced earlier.

Colorado's renewable resource development has made significant strides during the past few years. In 2000, Colorado had these resources on line: 1,149 MW of hydroelectric capacity; 51 MW of wind capacity; and 7 MW of biomass gas capacity. By late 2009, Colorado had 1,241 MW of wind power on line, on par with the state's 1,227 MW of hydropower. Colorado now ranks eighth among all states in wind energy generation capacity, according to the American Wind Energy Association (AWEA).[39] PSCo also purchases power from SunEdison's 8.3-MW central PV solar plant near Alamosa, and has announced a power purchase agreement with SunPower, who is building a 17 MW PV plant adjacent to the SunEdison plant.[40]

Several factors provided renewable energy development initial momentum in Colorado. The state has a highly-educated population that is widely committed to improving the state's environmental quality. Colorado is also the home to several scientific research institutions, including the NREL, and the Colorado Renewable Energy Collaboratory, referenced later in this report.

Colorado has abundant renewable resources. Colorado's Eastern Plains has high-quality wind resources, and most parts of the state enjoy an average of 300 sunny days per year. In addition, a variety of important initiatives established Colorado's leadership in renewable energy. These included, but are not limited to several important steps. PSCo pioneered a voluntary "green pricing" WindSource offering, which was started in 1997, and now supports more than 60 MW of wind. In 2001, the PUC determined that a large commercial wind plant was the most cost-effective new generation bid, save one small hydro plant.[41] This led to development of the 162 MW Colorado Green wind project in Prowers County. Another key development was the Interwest Energy Alliance's 2006 "backcasting" study, *Wind on the Public Service Company of Colorado System: Cost Comparison to Natural Gas*, which documented the customer cost savings of wind energy.[42]

Many consider the 2004 adoption of a RES as the most significant event in Colorado's progress to advance renewable energy. Proponents collected 115,000 signatures to place a measure on the statewide ballot, and Colorado voters passed

Given the constraints on the high-voltage system, the initial period of renewable energy growth in Colorado may be entering a new stage that will require new policies, including new ways of operating the power system and new transmission investments.

Amendment 37 in November 2004. This was the first state RES to be achieved by a popular vote. At that time, in 16 other states, RES laws were supported either through legislative or regulatory actions. Now, 36 states have similar RES laws.

Amendment 37 required IOUs to obtain at least 10 percent of their retail electricity supply from renewable energy by 2015. Three of Colorado's largest rural electric associations (REAs) and two large municipal utilities were subject to most of the same provisions in the RES, but were given the option to choose not to participate based on their members' vote. Two REAs— Intermountain Rural Electric Association and United Power — did so. However, the two large municipal utilities (Colorado Springs Utilities, and Fort Collins Utilities) elected to remain in the RES. Meanwhile, Holy Cross Energy, the state's third largest REA, vowed not only to comply with the RES, but to exceed its requirements.

In direct response to Amendment 37, PSCo acquired output from additional wind plants based on wind power's favorable economics, meeting the "10 percent by 2015" RES standard eight years early. Two and one-half years after Amendment 37 passed, in March 2007, Governor Ritter signed HB07-1281 into law, doubling the RES for IOUs to a minimum of 20 percent of retail sales from renewable energy by 2020. The new statute, adopted with broad bipartisan support in both chambers of the legislature, removed the opt-out provision for the larger REAs and municipal utilities, and attributed a more modest goal — a minimum of 10 percent of retail sales from renewable energy by 2020 — for REAs and municipal utilities with 40,000 or more customers.

The following description of HB07-1281 was produced by the Colorado Legislative Council:[43]

"The bill made several statutory changes to the renewable energy initiative (Amendment 37) passed by Colorado voters in 2004. Specifically, it expands the definitions of a "qualifying retail utility" to include all utilities, except municipally owned utilities serving less than 40,000 customers, and "eligible energy sources" to include recycled energy. The bill raises the standard for electricity generation from eligible energy sources for investor-owned utilities (IOUs) from:

- 3 to 5 percent for 2008 through 2010;
- 6 to 10 percent for 2011 through 2014;
- 10 to 15 percent for 2015 though 2019; and
- 10 to 20 percent for 2020 and after, and

establishes a new standard for electricity generation from eligible energy sources for rural electric cooperatives (RECs) and municipal owned utilities (MOUs) serving over 40,000 customers at:

- 1 percent for 2008 through 2010;
- 3 percent for 2011 through 2014;
- 6 percent for 2015 through 2019;
- 10 percent for 2020 and after.

With regard to standard compliance, the bill establishes bonuses for certain types of generation facilities. For all qualifying utilities, each kilowatt-hour of eligible electricity generated from a community-based project as defined in the bill will count as 1.5 kWh. For RECs and MOUs, each kWh generated from solar generation technologies that produce electricity before FY 2015-2016 will count as 3 kWh. However, utilities can take advantage of only one bonus for each kilowatt-hour of generated electricity. For IOUs and MOUs, the maximum allowable retail rate impact from meeting the standard is raised from 1 to 2 percent of the total electric bill annually for each customer. The current opt-out provision for RECs is eliminated, and RECs are required to submit an annual report to the PUC on or before June 1 of each year. However, reports submitted by RECs are not subject to the same compliance report review process as those submitted by IOUs.

Finally, the bill allows utilities to develop and own as utility rate-based property up to 25 percent of total new eligible energy resources if these resources can be constructed at reasonable cost compared to the cost of similar eligible energy resources available on the market. If the utility shows that its proposal provides significant economic development, employment or energy security benefits, the utility is allowed to own between 25 and 50 percent of total new eligible energy resources. The bill was signed by the Governor and became law on April 27, 2007. While this bill requires the PUC to revise or clarify the existing rules promulgated for the implementation of Amendment 37, this requirement does not force any additional evidentiary hearings. The PUC is not precluded from holding such hearings, but such hearings would be discretionary, and accomplished within existing budgetary resources."

At present, all Colorado utility-scale wind energy projects are located on the Eastern Plains. The location of the wind generation depends to a large extent on the quality of the wind resource in a particular area. Another important factor that determines wind farm location is the economic access to high-voltage transmission. Given the constraints on the high-voltage system, the initial period of renewable energy growth in Colorado may be entering a new stage that will require new policies, including new ways of operating the power system and new transmission investments.

Three complementary bills passed in 2006 and 2007 address a strategic approach for both new renewable energy generation and the transmission to connect to that generation:

■ HB06-1325 created the Transmission Task Force on Reliable Electricity Infrastructure to analyze transmission in Colorado and make recommendations designed to improve transmission development. The task force, in its Nov. 1, 2006 report, recognized that "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 also indicated that "today the system is strained and, if current trends continue, there will not be adequate transmission to meet the needs." Two key recommendations include: 1) utilities should identify and map the state's best renewable energy generation development areas, and 2) utilities should receive accelerated cost recovery when they build new transmission lines. These recommendations led to two important bills — SB07-91, and SB07-100 — that were passed during the 2007 legislative session.[44]

■ SB07-91 created a 16-member task force, appointed by the Governor and the legislature, that was to identify the best quality renewable energy resources to generate electric power in the state. The task force was asked to identify generation development areas (GDAs), defined as geographic sub-regions in Colorado sufficient to host at least 1,000 MW of renewable energy capacity. The study identified 10 GDAs. Eight are wind GDAs, located primarily in various areas of the eastern half of the state. Two solar GDAs were identified, one in the San Luis Valley and the other in the area south and southeast of Pueblo. The widely distributed *SB07-91 Report* has been used by utilities, developers, and regulators as they consider future generation and transmission plans. The map on the following page combines information from the wind and solar GDA maps produced in the *SB07-91 Report*.

▼ SB07-100, the legislation that created C.R.S. §40-2-126, states that the General Assembly finds, determines and declares that:

▼ A robust electric transmission system is critical to ensuring the reliability of electric power for Colorado's citizens;

▼ Colorado's vibrant economy and high quality of life depend on the continued availability of clean, affordable, reliable electricity; and

▼ The purpose of SB07-100 is to promote development of "clean, affordable, reliable electricity" by encouraging electric utilities to "promptly and efficiently improve" the transmission infrastructure in Colorado. The law created a process for designating beneficial Energy Resource Zones (ERZs) and an expedited review process for associated transmission projects. The law also authorizes rate-regulated utilities (PSCo and Black Hills Energy) to implement a transmission rate adjustment clause to recover costs related to the planning and development of transmission facilities. Independent transmission companies and utilities that own transmission assets that are not rate jurisdictional to the PUC (e.g. Tri-State and municipal utilities) are excluded from SB07-100 provisions.

The law also authorizes current recovery of costs associated with construction work in progress for transmission facilities. This change to state law means that IOUs no longer must wait for a transmission line to be put into service before the company can start collecting the cost of constructing the line.

The legislation requires IOUs to identify beneficial ERZs, and submit plans and applications to build transmission from these zones to connect to the existing transmission system. An important note: the legislation does not require the other major transmission-owning utility in Colorado (Tri-State) to similarly identify ERZs and submit plans to the PUC.

PSCo filed its latest 34-page report, *Senate Bill 07-100 Designation of Energy Resource Zones and Transmission Planning Report* on October 30, 2009.[45] The report describes:

▼ PSCo's transmission activities since the filing of its 2007 SB07-100 report,

▼ the five Colorado ERZs,

▼ PSCo's consideration of the work of the Western Governors' Association,

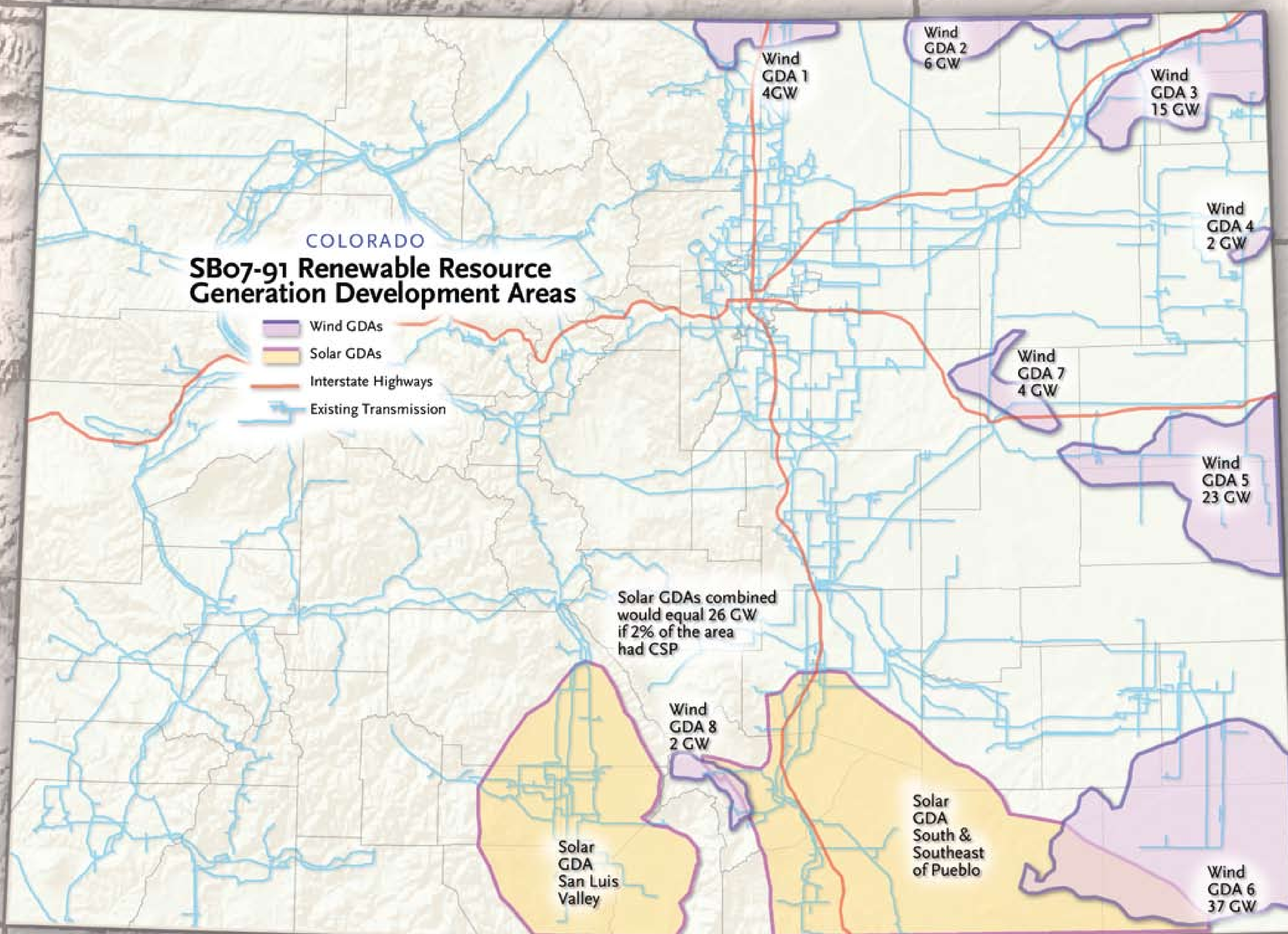
▼ a description of transmission planning methods, and

▼ the company's transmission plans

PSCo also provided the following description of their five beneficial ERZs:

Zone 1: In Northeast Colorado, Zone 1 includes all or parts of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties.

Zone 2: Zone 2 is in East Central Colorado, and includes all or parts of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson, Kiowa and Cheyenne Counties.



Source: Colorado Governor's Energy Office

Proposed PSCo Transmission and Switching Projects

	Project	Zone	CPCN Status	Currently Scheduled In-Service Date
1	Missile Site 230kV Switching Station	2	Not Required	2010
2	Midway-Waterton 345kV Transmission Project	3,4,5	Granted: 7/16/2009	2011
3	Pawnee-Smoky Hill 345kV Transmission Project	1	Granted: 2/26/2009	2013

Additional Proposed PSCo Transmission and Switching Projects

	Project	Zone	CPCN Status	Currently Scheduled In-Service Date
1	San Luis Valley- 'Calumet-Comanche 230/345kV	4,5	Filed: 5/14/2009	2013
2	Missile Site 345kV Substation	2	Noticed in Rule 3206 9/16/2009	2013
3	Lamar – Front Range 345/500kV	3	Plan to be filed in 3rd Quarter 2010	2016-2017
4	Lamar – Vilas 230/345kV	3	Plan to be filed in 3rd Quarter 2010	2016-2017
5	Ault – Cherokee 230/345kV	1	TBD	2015-2016
6	Pawnee – Daniels Park 345 kV	1	TBD	2016-2017

Zone 3: Zone 3 is in Southeast Colorado, and includes all of parts of Baca, Prowers, Kiowa, Crowley, Otero, Bent and Las Animas Counties.

Zone 4: Zone 4 is in the San Luis Valley, and includes all or parts of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties.

Zone 5: Zone 5 is in South-Central Colorado, and includes all or parts of Huerfano, Pueblo, Otero, Crowley, Custer and Las Animas Counties.

In their report, PSCo provided the charts, to the right, of transmission projects being considered. Details of the current status of these projects are contained in the company's October 30, 2009 report.

What high-voltage transmission developments are under way at Tri-State?

Tri-State has been investing in its transmission system. By the end of 2011, Tri-State will have completed more than 40 ongoing projects in Colorado to maintain and upgrade the reliability of its transmission system. These investments exceed $300 million. Some of the more significant projects include partnerships with the Western Area Power Administration on the Cheyenne-Ault project, which increased TOT3 capability by 75 MW and the Story-Erie rebuild and upgrade, which will ensure stable load serving capability in northeastern Colorado for many years.

Another key project is the Big Sandy-Lincoln-Midway 230 kV upgrade. This upgrade is an important element necessary to assist with delivery of potential wind energy resources from eastern Colorado to the Front Range. Another key piece of this investment portfolio is the San Luis Valley-Calumet, Calumet-Comanche and Comanche-Walsenburg projects. See the map to the right.Tri-State began developing these projects several years ago and has subsequently partnered with PSCo to increase the project capability and ensure adequate transmission to the two solar GDAs identified in the *Senate Bill 07-91 Report*, i.e. the key San Luis Valley area and the "South and Southeast of Pueblo" area, as well as the wind rich wind GDA 8 near Walsenburg.

Tri-State's board of directors recently authorized construction of the Burlington-Wray 230 KV upgrade. This project is another essential improvement to the eastern Colorado transmission system that will facilitate the delivery of eastern plains renewables to the Front Range. Tri-State will pursue significant elements of the Eastern Plains Transmission Project: Energy Center-Burlington, Energy Center-Burlington-Big Sandy-Road 125-Missile Site and Energy Center-Comanche are all planned projects at either 345 kV or 500 kV. Energy Center is located about 20 miles north of Lamar-Colorado. Tri-State also plans to construct a 230 kV intertie between Lamar and Energy Center.

Tri-State is proposing the San Juan Basin Energy Connect Project, involving the construction of a 230 kV transmission line from the Farmington, New Mexico area to Ignacio, Colorado. This line is needed to provide the power delivery infrastructure for the San Juan Basin that will relieve transmission constraints, serve new loads and offer economic development through renewable energy opportunities.

Tri-State remains actively involved in the High Plains Express Project and the Sun-Zia Southwest Transmission Project. Both projects can potentially greatly

Route Refinement

Route segments have been modified since the August 2009 scoping meetings based on public comments, field and aerial photo review in addition to further analysis of key routing factors including:

- Proximity to residences, including subdivided areas
- Parcel lines
- Agricultural irrigation systems
- Existing electric lines
- Existing canals and roads
- Sensitive or protected lands
- Wet areas, including wetlands
- Public and private airstrips
- Density of homes and buildings associated with Blanca and Fort Garland
- Terrain and vegetation
- Historical features and monuments
- Cemeteries

Each project section has been identified on the map to the right and reasons for route modification outlined below.

1. Routes were modified to make best use of existing linear features such as roads, electric lines, and canals while minimizing impact to irrigated agriculture and rural residential areas.

2. Route modifications in this area included the review and removal of a route futher north of Highway 160, and refinements in the areas south of Highway 160 to minimize impact to residences and historic Fort Garland.

3. As a result of public comment, additional routes were studied in this area both north and south of Highway 160 west of La Veta Pass. Upon further review, the routes to the south of Highway 160 were removed from further consideration due to the potential impacts to residential subdivisions in the area and the difficult terrain.

4. In the area southeast of La Veta Pass, additional routes were studied and all routes were removed from consideraion due to the difficult terrain, density of residences, and large amount of forested area with dense stands of trees. The removal of these routes also resulted in the removal of some routes north of Highway 160 in the area east of Silver Mountain.

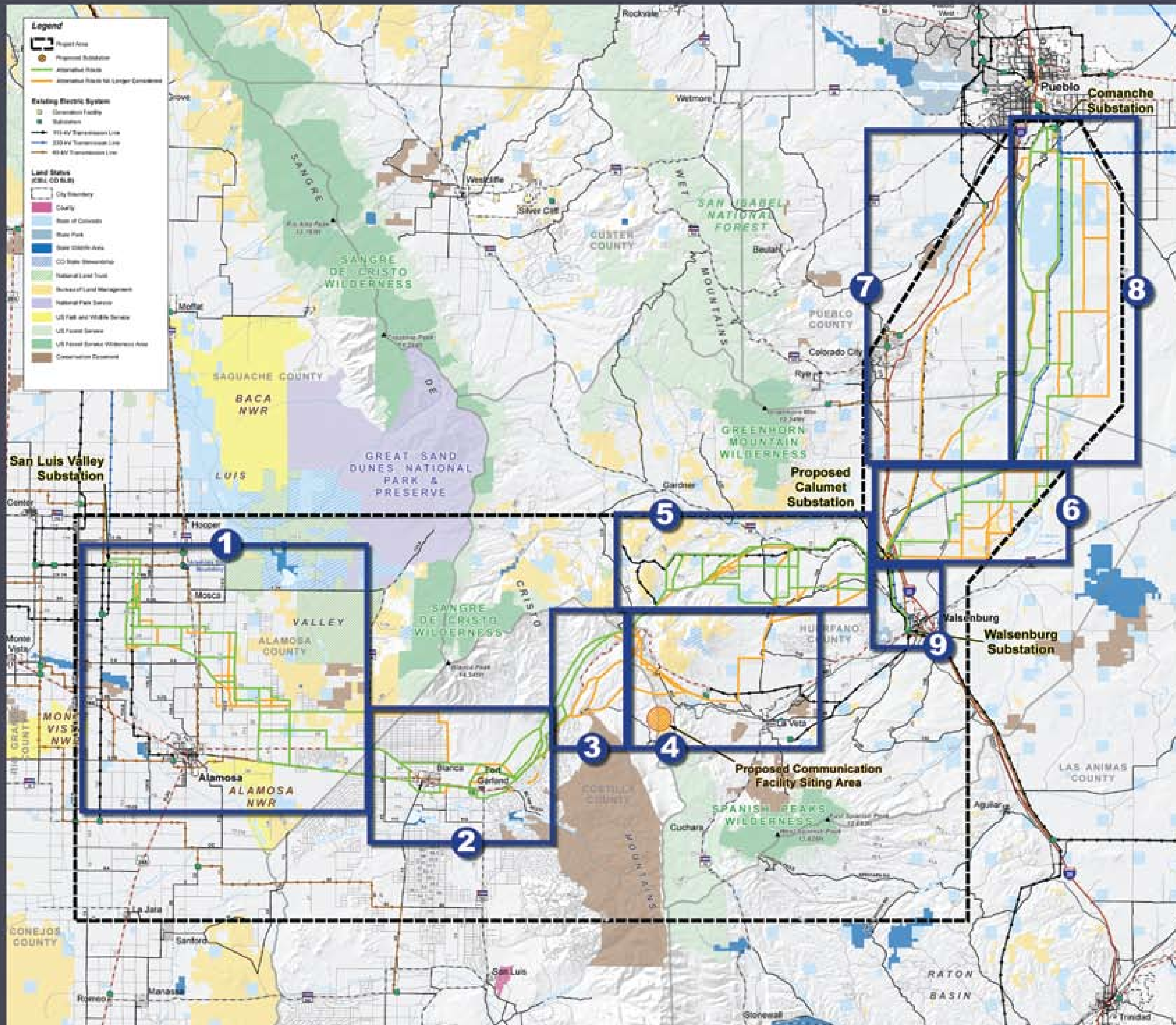
5. Public comment suggested that the project should make use of the existing transmission corridor in this area as well as making better use of parcel lines and other land divisions. Modifications were made to make better use of these features. Field verification of existing homes also allowed for adjustments around residences.

6. Routes were revised in this area to maximize the use of parcel lines and other existing linear features while avoiding sensitive areas associated with Bradford Reservoir and Cuchares Reservoir.

7. Routes were removed from consideration along I-25 and the existing 115-kV line due to the number of residences and subdivided areas.

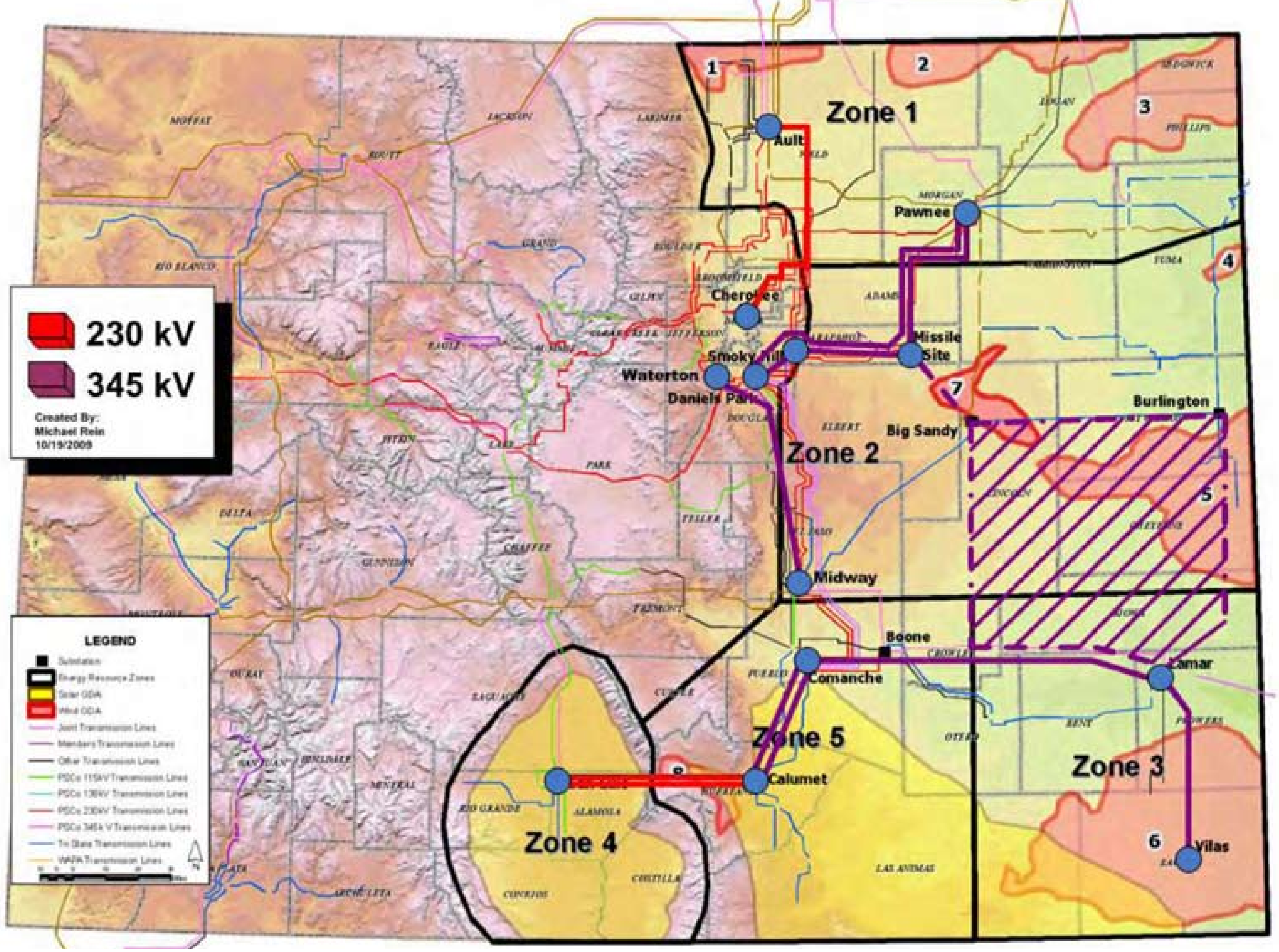
8. Based on scoping comments additional routes were studied to the east of the existing 230-kV transmission line but two of the three were removed because feasible options existed along the existing railroad and transmission line. One route east of the subdivided area was added.

9. No modifications to routes were made in this area. The existing 115-kV line is proposed to be rebuilt to connect the proposed Calumet Substation with the existing Walsenburg Substation.



Sources: Tri-State Generation and Transmission Association, Xcel Energy

Proposed Transmission Projects



Sources: Tri-State Generation and Transmission Association, Public Service Company of Colorado

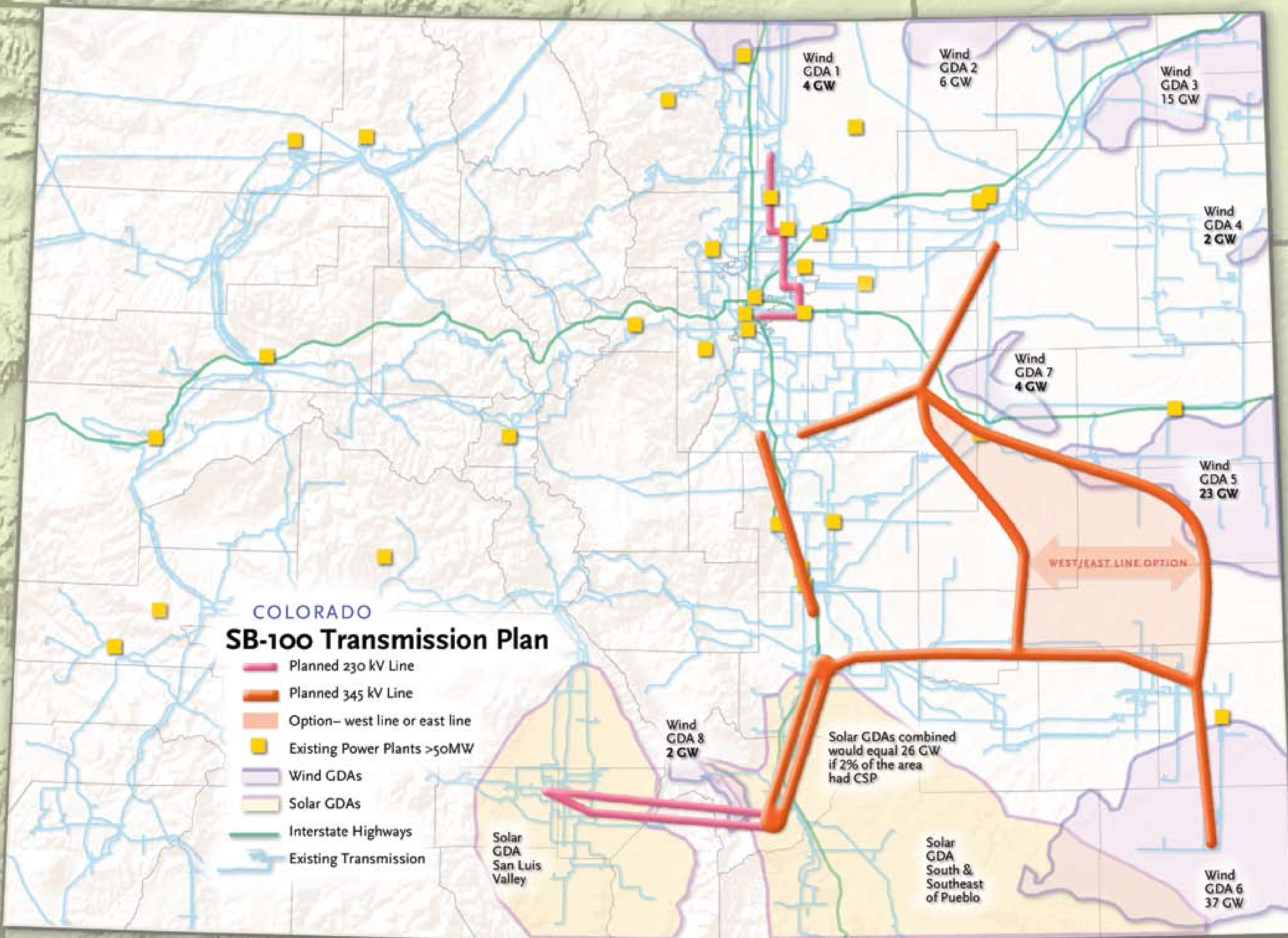
increase power transfers across Colorado and between Colorado and its neighbors to the north and south.

Is transmission infrastructure sufficient either in Colorado or nearby to deliver the renewable energy needed to meet a 20x20 goal?

Under current demand forecasts, greater deployment of utility-scale renewable energy is critical to Colorado's pathway toward meeting the 20x20 goal. The viewpoint expressed in the Colorado Energy Forum's report, *More Transmission Needed: Colorado's Electric System And Why It Needs Expanding*[46] and in this report's view, the state's current transmission system does not have sufficient capability to deliver the quantity of generation contemplated in a plausible pathway to meet the 20x20 goal, nor is it currently built out to the places in the state where the greatest wind or solar energy resources are located. In short, Colorado's existing high-voltage transmission system was not built to take best advantage of the state's rich utility-scale renewable resource potential.

According to wind developers, cost-effective wind bids to PSCo have been withdrawn or have been rejected or downsized due to inadequate remaining available transmission capability at the point of interconnection.

Governor Ritter has said that "transmission is among the most significant impediments to the building out of renewable resources."[47] Electric power systems across the country, including Colorado, do not have the benefit of pre-existing major high-voltage bulk power systems. Prospects in Colorado are improving because utilities are proposing to create a major high-voltage transmission backbone reinforcement along the I-25 corridor. A serious mismatch exists, however, because the combined transmission planning and implementation period takes much longer than the time needed to expand renewable energy generation. Until the I-25 backbone, and other Colorado and, possibly adjacent state transmission infrastructures reinforcements are built, Colorado's opportunities for major increases in utility-scale renewable energy projects are limited. In addi-



Source: Governor's Energy Office

Even though developers built their own radial transmission lines, the seven wind projects were selected for purchase by PSCo because they had the lowest overall evaluated cost to PSCo customers.

tion to improving the transfer capability of Colorado's backbone transmission system, significant transmission expansion is needed, preferably at the highest reasonable voltage rating, to interconnect high-quality renewable resources in outlying GDAs. Finally, in those locations, investments in transmission "collector" systems will be needed to fully interconnect these resources.

Colorado is not the only state to face this transmission challenge. National leaders in government and industry, clean energy advocates, environmental groups, academics, and other electricity sector entities have identified the need to build thousands of miles of new high-voltage transmission to bring major blocks of renewable energy to load centers. Texas, for example, has approved a $5 billion transmission plan to connect 11.5 gigawatts of wind power to the grid. Other states and regional transmission organizations nationwide have begun detailed studies of similar transmission infrastructure investments.

One reason Colorado must examine transmission so closely at this juncture is that, in general, our state utilities have not needed to invest heavily in transmission until recently. Natural gas plants, the generation choice preferred by many utilities during the past three decades, typically are sited relatively close to loads, so they require fewer long transmission lines.

A May 2008 in-depth DOE report, *20 Percent Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply*[48] highlights the importance of increasing renewable energy on the grid. The report is one of many studies that reinforce the conclusion that new generation is needed to meet demand, and that this new generation, including renewable energy, will require a major transmission grid expansion.

How did Colorado's existing wind farms address transmission issues?

Of the 10 Colorado wind farms that provide energy to PSCo, seven send energy to the PSCo grid via radial 230kV "wind only" interconnection transmission lines built and owned by project developers. (Some call these lines "extension cords" because of their length.) For example, three of these lines are 44, 55 and 70 miles long. The lines were built by project developers to deliver energy to the PSCo transmission network at interconnection points where the PSCo system could accept and integrate the energy.

Developers built the lines for several reasons. First, they could build the lines more quickly, sometimes in less than one year, because they did not need to submit an application and obtain a Certificate of Public Convenience and Necessity (CPCN) from the PUC, a process that has historically taken one to two years. Second, radial transmission lines from a generator to the utility network in some cases can be categorized as a component of the generation facility, rather than as "transmission facilities." However, even though developers built their own radial transmission lines, the seven wind projects were selected for purchase by PSCo because they had the lowest overall evaluated cost to PSCo customers.

Once wind plants connect to PSCo's system, they have a favored status — known as "network" service — to bring their wind energy to PSCo's markets. "Network" service means the independent power producers that sell their output to the utility are treated the same as plants in the utility network.

In some cases, wind plants that submitted bids to the utility were not able to sign contracts and build at the anticipated size because of insufficient available transmission capability through the existing utility network.

As documented throughout this report, Colorado wind plants have provided transmission "extension cords" instead of building transmission lines that serve in the capacity of a networked transmission system. Although such lines can be built quickly, planning and investments that would replace them with a generation delivery system is complex. A generation delivery system, however, offers not only additional benefits of improved reliability and security and options for moving power, but also provide access to additional markets and improved services.

What potential technology and policy development "game-changers" could influence the path to the 20x20 goal?

A number of emerging technologies and policy developments could change whatever path is selected to reach the 20x20 goal. We highlighted the following potential "game-changers": electrification of the transportation sector, the potential for Smart Grid, increasing emphasis on distributed generation, greater penetration of photovoltaics, breakthroughs in carbon capture and storage technologies, the potential impact of shale gas on the electricity sector, the potential for new transmission technologies, feed in tariffs, and a national renewable electricity standard. This list illustrates only a few of what may be

Game-changers? Electrification of the transportation sector, the potential for Smart Grid, increasing emphasis on distributed generation, greater penetration of photovoltaics, breakthroughs in carbon capture and storage technologies, the potential impact of shale gas on the electricity sector, the potential for new transmission technologies, feed in tariffs, and a national renewable electricity standard.

other possible "game changers" that could emerge over the next decade. These potential "game-changers" serve as examples, intended to convey the many associated uncertainties involved in attempting to predict a future outcome.

1. Electrification of the transportation sector:

The United States faces a national security threat due to a myriad of well-documented pressures applied to the nation's long-term liquid fuels supply outlook. Several major backdrop issues converge here — a mounting concern about declining global petroleum discoveries and ever-increasing petroleum depletion rates, the outflow of dollars increasing our national deficit, plus a rapid increase in the world's automobile population.[49] In partial response to these concerns, many are considering the potential for electrifying a portion of the transportation sector. A Sept. 3, 2009 story in the Economist, *The Electric-Fuel-Trade Acid Test*[50] discusses how, after many false starts, battery-powered cars seem to have found their niche. The article questions whether electric vehicles (EV) are only an interesting niche product or if they will transform motoring.

An article in the April 2009 issue of Solar Today, *Plugging in Transportation,* makes the case that a viable green option may be close.[51] The article states that "a Chevy Volt extended-range electric vehicle (EREV), a straight-electric vehicle (EV) Ford Transit light-duty van and a Toyota Prius plug-in hybrid (PHEV) could be available as soon as 2010, and many other EVs and PHEVs are in the offing. With an EREV, an electric motor drives the vehicle, and a small engine acts as a generator to recharge the batteries as needed. In a PHEV, both a motor and an engine drive the vehicle either in parallel or in series. Indeed, nearly every major auto manufacturer plans to have an EV on the market by 2012."

The Solar Today article states, "Boulder, Colorado is working to incorporate PHEVs and vehicle-to-grid benefits. PSCo is installing fiber-optically connected monitoring equipment for transformers and other grid components and smart meters for homes within its distribution system to develop a SmartGridCity.[52] The systems will tell electric customers which appliances are drawing the most power and enable users to turn them on or off from a remote computer. Boulderites also will be able to plug in electric-drive vehicles to charge them when rates are low or to feed power into the grid during peak power periods.

Recharging huge fleets of EVs at night could increase the amount of baseload generation needed. If charging stations were equipped with "smart meters" capable of responding to instructions from grid operators, grid-integrated EV fleets also could provide an additional tool to manage reliability and wind variability. NREL-conducted analyses reveal that PHEVs will promote greater use of renewable energy, particularly wind power. The DOE recently awarded $8 billion in loans for advanced vehicle technologies. [53]

Trade-offs are expected to result should PHEVs penetrate the market according to many projections. Concerns have been expressed. For example, Southern California Edison (SCE) has identified Santa Monica as a community with many potential battery-car customers that may require transformer upgrades. According to SCE, a typical Santa Monica circuit, which serves about 10 households, may be overloaded should two or three of those customers charge vehicles simultaneously, even if they do so overnight during off-peak hours. SCE has noted that while surplus power is available at night at cheaper rates, the grid needs adjustments to handle such charging. Additional or larger transformers may be needed in neighborhoods with numerous plug-in car owners. SCE said that "If all those people charge their vehicles at off hours, in the middle of the night, a lot of our system is designed so the transformers can cool down at night. That's part of how they are able to function at full capacity during the day."[54]

2. The potential for Smart Grid:

In its most promising form, the smart grid is an enabling set of technologies that make possible the better use of renewable energy, energy efficiency, voltage control, and other means to make the power grid more reliable and efficient.[55] The Electric Power Research Institute defines the smart grid as a "two way flow of electricity and information in an automated electricity delivery network. The smart grid is interconnected by a communication fabric that reaches every device and is highly instrumented with advanced sensors and computing."

Smart grid technologies fall into two categories, utility-focused and customer-focused.

Utility-focused technologies. Utility companies can use smart grid technologies to improve the reliability and efficiency of their power delivery systems. The following examples illustrate some of these technologies and functions.

Utility-focused technologies that utilities will adopt and operate on their transmission and distribution system. These will be largely invisible to most electric customers except for more efficient and reliable power system operations.

An example of a smart grid technology that operates on the transmission system is one that regularly and frequently checks the state of the transmission system to determine if areas are, or are about to be, overloaded. Operated through technologies known as synchrophasors, this element of the smart grid helps maintain reliability.

According to the North American Synchrophasor Initiative[56]:

"Synchrophasors are precise grid measurements...taken at high speed (typically 30 observations per second — compared to one every 4 seconds using conventional technology). Each measurement is time-stamped according to a common time reference. Time stamping allows synchrophasors from different utilities to be time-aligned (or "synchronized") and combined together providing a precise and comprehensive view of the entire interconnection. Synchrophasors enable a better indication of grid stress, and can be used to trigger corrective actions to maintain reliability."

The DOE recently announced ARRA funding totaling $53.9 million that will be used by the Western Electricity Coordinating Council (WECC) for the implementation of its Western Interconnection Synchrophasor Program (WISP). The funding will help improve the reliability of the bulk transmission power grid that spans 14 western states.

The interconnection-wide synchrophasor system will enable smart grid functions, such as improved integrated system operation and increased transmission capability.

One promising utility-focused technology and function of the smart grid is to integrate small-scale renewable resources into the power system. This integration is important because today's power system is designed only to deliver power to end-users. It is not designed to both deliver power to end users and take in power from those same users who have an interconnected solar power or other generator on their property. Smart grid communication technologies will enable power system operators to integrate these customer-sited resources in to the power system. Two such technologies are:

- Solar, wind, or fuel cell generators and a host of new generating technologies distributed around the utility system.
- PHEVs that can feed power into the grid when an advanced meter communicates that the grid requires power to meet a peak in demand, and that can pull power from the grid to charge batteries when the power system is not under stress.

Customer-focused technologies. The smart grid garners attention because of its potential to encourage customers to reduce their energy use or shift it to other times. This potential relies on advanced meters, appropriate rate structures that reward customers for reducing their consumption when the demand on the power grid is at its highest, and on customer response to the price or other informational signals designed to encourage this behavior.

One way to encourage ongoing response to signals is to automate customers' appliances. If power lines or power plants are reaching capacity on a hot summer day, the smart grid can send signals that automatically turn down an air conditioner or a pool pump, for example, based on the customer's preferences and the utility's needs.

Examples of technologies that play a part in the smart grid include the following:

- Advanced meters are a tool and a means for communication between the energy suppliers and users. They are a key enabling technology that makes a smart grid work.
- Smart appliances — thermostats, pool pumps, dryers, air conditioners, and lighting systems — that can receive and respond to indications that the energy system may be nearly overloaded.
- Display devices and automated controls that allow electric customers see when their energy use is highest and to respond by turning down air conditioning, lights or other energy-using devices.

The transition to these technologies will face many challenges. Utilities will need to employ far more computers and sophisticated electronics to integrate thousands of devices, some of which generate power, some of which reduce the need for power and some of which monitor the state of the power delivery system. The industry that supplies high-technology smart meters, appliances, sensors, and other devices to the energy industry will need to ensure that all of these technologies can communicate and be integrated with one another coherently and in coordination — a function referred to as inter-operability. Customers will increasingly need to adopt, use, and respond to new technologies, new price signals, and other information that currently are largely unproven.

Investments of $3.4 billion have recently been made to spur the transition to Smart Energy Grid.[57] The DOE has announced a major public-private partnership, aimed at creating tens of thousands of jobs, saving energy and empowering customers to cut their electric bills. President Obama has announced the largest single energy grid modernization investment in U.S. history. The end result is intended to promote energy-saving choices for customers, increase efficiency, and foster the growth of renewable energy sources such as wind and solar. The awards, part of the ARRA, will be matched by industry funding for a total public-private investment of more than $8 billion. The program aims to create tens of thousands of jobs, with benefits to customers in 49 states due to investments in a stronger, more reliable grid.

One hundred private companies, utilities, manufacturers, cities and other partners have received Smart Grid Investment Grant awards. The DOE is using $400 million to fund several grid modernization projects across the country that will significantly reduce the amount of power wasted from when it is produced at a power plant to when it reaches a house. By deploying digital monitoring devices and increasing grid automation, the awards will increase system efficiency, reliability and security, and will help link up renewable energy resources with the electric grid. Another $2 billion will be used for activities to integrate various components of a smart grid.

The DOE is funding a range of projects that will incorporate the various components into one system or cut across various project areas — including smart meters, smart thermostats and appliances, syncrophasors, automated substations, PHEVs, and renewable energy sources. The activity will:

- Leverage more than $4.7 billion in private investment to match the federal investment.
- Make the grid more reliable, reducing power outages that cost American customers $150 billion per year — about $500 for every man, woman and child in the United States.
- Install more than 850 sensors — called Phasor Measurement Units — that will cover 100 percent of the U.S. electric grid and make it possible for grid operators to better monitor grid conditions and prevent minor electrical system disturbances from cascading into local or regional power outages or blackouts. This monitoring ability also will help incorporate into the grid large blocks of intermittent renewable energy, such as wind and solar power, to take advantage of clean energy resources when they are available and make adjustments when they're not.
- Install more than 200,000 smart transformers that will make it possible for power companies to replace units before they fail, thus saving money and reducing power outages.
- Install almost 700 automated substations, representing about 5 percent of the nation's total that will allow power companies to respond faster and more effectively to restore service when inclement weather downs power lines or causes electricity disruptions.
- Provide utilities with the necessary tools to better prevent outages and respond more quickly to make repairs when outages occur.
- Empower customers to cut their electricity bills. Recovery Act money combined with private investments will put the United States on pace to deploy more than 40 million smart meters in homes and businesses during the next few years that will help customers cut their utility bills.
- Install more than 1 million in-home displays, 170,000 smart thermostats, and 175,000 other load control devices to enable customers to reduce energy use. Funding also will help expand the market for smart washers, dryers, and dishwashers, so that American customers can further control energy use and lower electricity bills.
- Put the United States on a path to secure 20 percent or more of our energy from renewable sources by 2020.
- Reduce peak electricity demand by more than 1,400 MW — the equivalent of several larger power plants — and save billpayers more than $1.5 billion in capital costs and help lower utility bills.

The DOE recently announced Smart-Grid grants to two Colorado electric utilities. Black Hills Energy will install 42,000 smart meters and communications infrastructure that will help facilitate meter reading and provide a pilot program for a dynamic pricing program. Recovery Act funding for the project is $6,142,854; total project value, including cost share is $12,285,708. Fort Collins Utilities will install 79,000 smart meters and in-home demand-response systems, smart thermostats and air conditioning and water heater control switches; automate transmission and distribution systems; and enhance grid security. Recovery Act funding for the project is $18,101,263; total project value, including cost share is $36,202,527.

During the past few years energy planners have increasingly focused on shale gas, and many suggest that it already has become a "game changer."

3. Increasing emphasis on distributed generation:

Distributed generation (DG) — also called on-site generation, dispersed generation, embedded generation, decentralized generation, and decentralized energy — generates electricity from many small energy sources. Accelerated growth in DG (often characterized by PV, which generates electricity on the customer's side of the meter) could reduce peak demand, overall consumption, and slow the need for distribution infrastructure upgrades. A recent report by The New Rules Project, *Energy Self-Reliant States*[58] proposes that DG could mitigate the need for utility-scale renewable energy and high-voltage transmission development. Given load growth, and since the grid serves as a "battery" for many DG technologies, and when comparing the economics and technology of expanding the grid versus DG, it remains to be seen whether DG can supply enough power to make a significant impact on the need for more supply-side resources.

4. Greater penetration of photovoltaics:

The cost of manufacturing PV has dropped from over $100 per watt in 1970 to a range of between $1 and $3 per watt today. Some are optimistic that the price will drop even further due to the convergence of a variety of technological, market, and policy changes. One positive indicator is that the number of PV patents has increased substantially during the past few years. The market for PV is almost infinite given the fact that two billion people in the world are without electricity. Like the cell phone, PV has the potential to be a technology that leaps over the central fossil, nuclear, hydroelectric plants, and related transmission systems that have characterized the electricity sector to this point. Future cost reductions are expected to result from process cost reductions (economies of scale, materials, automation) and improved cell efficiency (cell structure, process and materials innovation).

A 50-page report by the Lawrence Berkeley National Laboratory, *The Installed Cost of Photovoltaics in the U.S. from 1998-2008*[59] presents detailed information regarding cost PV reductions. Recent reports indicate installed PV costs as low as $3.50 per watt for utility-scale projects, and installed costs in the range of $5 to $6 per watt for residential projects. For updates, NREL is an excellent source for PV information.[60]

5. Breakthroughs in carbon capture and storage (CCS) technologies:[61]

CCS is used to mitigate the contribution of fossil fuel emissions to global warming, based on capturing CO_2 from large point sources. Captured CO_2 then must be permanently stored, away from the atmosphere. This represents a substantial technological and liability challenge. More than $3 billion of ARRA funds are dedicated to the advancement of CCS technology. Successful commercialization of CCS holds promise to reduce CO_2. However, the pathway to success with CCS may take many years.

6. The potential impact of shale gas on the electricity sector:[62]

Shale gas is natural gas produced from shale. It is completely distinct from kerogen (popularly known as "oil shale"). Shale gas has become an important source of natural gas in the nation in just a few short years.[63] Because gas-bearing shales ordinarily have insufficient permeability to allow significant fluid flow to a well bore, most shales are not commercial sources of natural gas. Shale has low matrix permeability, so gas production in commercial quantities requires fractures to provide permeability. The shale gas boom in recent years has been due to modern hydraulic fracturing technology to create extensive artificial fractures around well bores.

According to author Daniel Yergin in a *Wall Street Journal* article dated Nov. 3, 2009:

"Proven (U.S) reserves have risen to 245 trillion cubic feet (Tcf) in 2008 from 177 Tcf in 2000, despite having produced nearly 165 Tcf during those years. The recent increase in estimated U.S. gas reserves by the Potential Gas Committee,[64] representing both academic and industry experts, is in itself equivalent to more than half of the total proved reserves of Qatar, the new LNG powerhouse. With more drilling experience, U.S. estimates are likely to rise dramatically in the next few years. At current levels of demand, the U.S. has about 90 years of proven and potential supply — a number that is bound to go up as more and more shale gas is found." A recent report by MIT's Technology Review, *Natural Gas Changes the Energy Map* provides details on this technology.[65]

During the past few years energy planners have increasingly focused on shale gas, and many suggest that it already has become a "game changer." Optimistic supply forecasts and the prospect for price stability (albeit higher than today's depressed prices for conventional natural gas) have caused many utility planners to reconsider their traditional hesitance to rely on natural gas for baseload electric power generation. Despite the optimism, many utility executives are cautious about ramping up the use of gas to generate a larger fraction of the electric power mix, as utilities have been stung before by the fuel's volatile prices, and they remain reluctant to make long-term commitments to gas by building or expanding plants. Others are concerned about the long-term viability of shale gas, citing concerns about unexpectedly high depletion rates,[66] land impacts, water consumption, and the potential for chemical pollution of water aquifers. Some shale gas developers halted their plans to drill for shale gas within the upstate New York watershed, an environmentally sensitive region that supplies unfiltered water to nine million people.

7. The potential for new transmission technologies:

Thomas Edison would recognize the technologies used for long-distance power transmission today. These industry-standard transmission technologies are reliable and have proven their worth through many decades. However, new transmission technologies offer a promise that may result in two to five times the throughput of conventional lines. These are emerging technologies, and have not sufficiently proven to be economically competitive or ready for full commercialization. Given these caveats, three examples of today's leading advanced transmission technologies are described below:

- Aluminum-conductor, steel-supported (ACSS) transmission conductors with ultra high-strength (UHS) cores: Southwire Company's Ultra High Strength Core HS285® ACSS conductors address the need for higher capacity through existing rights-of-way and re-conductoring projects. Advantages of HS285® include its steel core (no composites) and a lower price point than some competing advanced transmission technologies.[67]
- Aluminum Conductor Composite Reinforced (ACCR): 3M's all-aluminum-based ACCR, for which Southwire is the contract manufacturer, can double the capacity of an existing line without exceeding the mechanical or clearance limits of existing towers. Where new lines are necessary to bring renewable energy from remote areas to load centers, 3M ACCR can be installed on sections where permitting, environmental impacts, or aesthetics raise issues or cause delays. In those sections, 3M ACCR can be installed using existing, fewer or shorter structures. Construction then can continue with conventional materials.[68]
- American Superconductor's Superconductor Electricity Pipelines combine conventional underground pipeline construction techniques with revolutionary, high-capacity superconductor cables and proven multi-terminal DC-AC power electronic converters. The underground construction technique enhances aesthetics and increases security against natural or man-made threats. The company also points out that the voltage source converters "allow precise amounts of electrons to be metered out [in an interstate line] into an intervening state if that state wants to buy some 'green electrons' and to therefore put in place just the transmission assets needed to support the green electrons."[69]

8. Feed in tariffs (FIT):[70]

Feed-in tariff policies provide a guaranteed high price for owners of DG equipment that "feed in" power to the electric utilities. This policy option has proven to be an effective spur to renewable energy development in certain European countries. An increasing number of countries and some states in the U.S. are considering, experimenting, and adopting FIT policies. These policies have not yet been put to a lengthy test in the United States. If FIT policies are to be effectively deployed, they will need to be designed appropriately, as there is a potential for a short burst in benefits, but at additional costs, that could lack incentives to keep PV prices low. The REDI report does not propose a policy direction for Colorado regarding this potential game-changer.

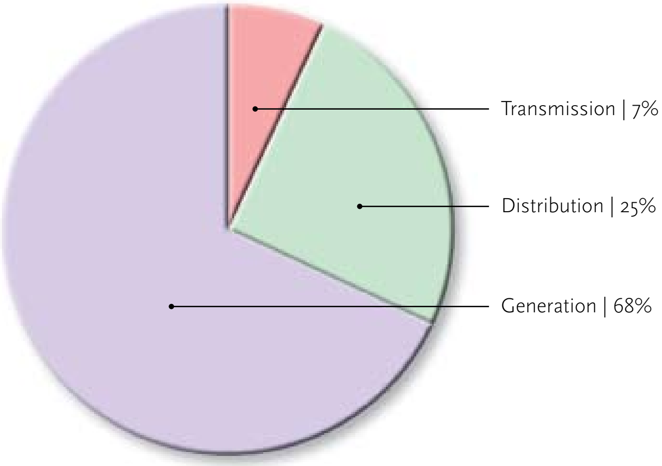
9. A national renewable electricity standard (RES):

A national RES would provide a major signal to the market that the nation is prepared to pursue a course of sustainable orderly development for renewable energy. NREL recently produced a 30-page report, *Comparative Analysis of Three Proposed Federal Renewable Electricity Standards*,[71] providing detailed information about various approaches under consideration in the U.S. Congress. A national RES is pending in the U.S. Senate.[72] Should a national RES become the law of the land, this key policy development would provide greater market confidence to spur even increased investment in renewable energy technologies and projects.

What about placing high-voltage transmission underground?

Placing high-voltage transmission on overhead towers has the benefits of lower maintenance and overall costs. The drawbacks relate primarily

National Average Cost of Electricity

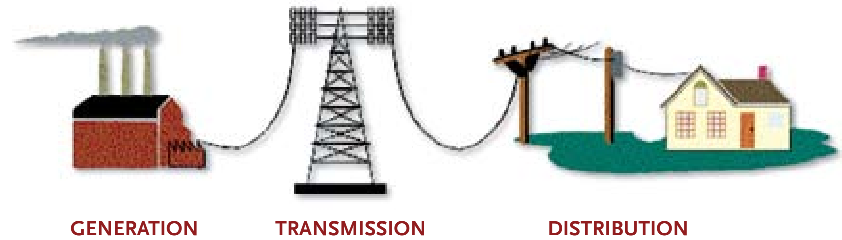


Source: USDOE Energy Information Administration

to aesthetics, however, and that often engenders landowner resistance. Deploying high-voltage transmission underground primarily helps to avoid potential aesthetics-related resistance. However, underground transmission has drawbacks compared to overhead transmission, including much higher costs, more difficult maintenance, and longer outages resulting from delays in repair time. An article by the technology editor of *Transmission and Distribution World*[73] states: "Two decades ago, underground lines cost 20 times or more than overhead lines. Unless you were in a large metropolitan area with no other realistic option, promoting underground transmission was not a career-enhancing decision. However, a decade ago, the price multiplier had dropped to 10 times. Today, there are significant lengths of 230-kV underground transmission operating in the United States, and the number of 345-kV underground transmission projects is exploding."[74]

Of significance to the topic of underground transmission, the Colorado General Assembly in 2000 granted the PUC statutory authority to review a county commission's transmission siting decision, should the affected utility seek to overturn the county's decision. In two contested cases, county commissioners (i.e., San Miguel County[75], and Adams County[76]) conditioned their land use approvals of a transmission application by Tri-State on requirements that the utility place its planned transmission expansion (in certain sections of their counties) underground. The counties' siting approvals contained the condition that the additional costs of placing the transmission lines underground must be borne by the utility's customers, i.e., the additional costs would not be borne entirely by the local residents. The two counties' land use decisions both led to appeals by Tri-State to the PUC. In both cases, the PUC rejected the counties' conditions that the additional cost of placing the transmission underground should be paid by the utility. The San Miguel County case was initiated in 2001, and the PUC decision is still under appeal. The Adams County case was initiated in 2007, and the PUC decision case is currently under appeal. The question of whether lines should be deployed underground or overhead, and who should pay for the incremental cost, is a serious consideration. Most new high-voltage transmission construction planned for Colorado will be overhead. However, the topic of underground transmission and the potential for protracted procedural delays will remain a challenge, unless policy changes occur.

The Three Components of the Electricity Sector



Do we know what new transmission may cost?

The electricity sector is divided into three major component parts: generation, transmission, and distribution, as illustrated above.

Historically, transmission has not represented a major fraction of the electric customer's utility bill. The graph above indicates that nationally, transmission represents approximately 7 percent of the average cost of electricity.

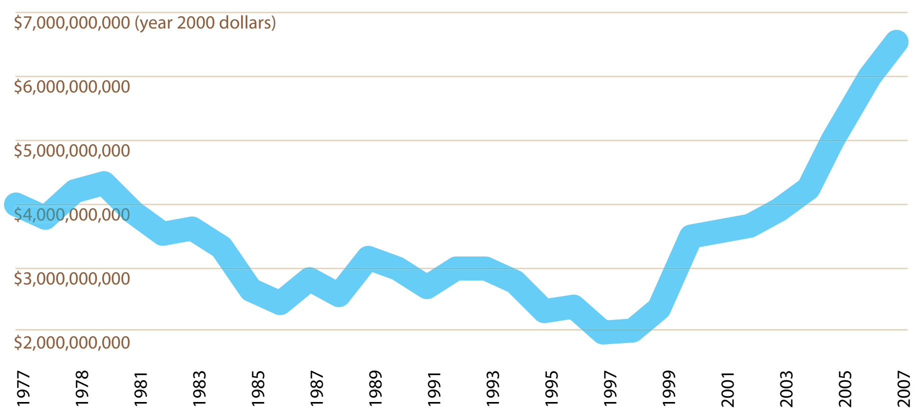
Too many competing assumptions and unknowns exist for this report to attempt a precise estimate of the costs of new renewable energy generation and high-voltage transmission. The cost of transmission systems by itself varies considerably, depending on the type of terrain it must pass over (or around), the voltage level of the transmission lines, and many other factors.

The Edison Electric Institute (the trade association that serves the IOUs) produced transmission cost estimates as part of its 34-page report published in November 2008, authored by the Brattle Group, *Transforming America's Power Industry: The Investment Challenge 2010-2030*.[77] The report estimates the potential need of $298 billion for combined low-voltage and high-voltage transmission expansion in the U.S. by 2030. See the charts on the following page.

To help better understand the cost of transmission, we offer the table on the following page. It shows estimates of various component costs used in the Western Governors' Association's Western Renewable Energy Zone Initiative. Note that higher voltage lines have higher per-mile costs but lower per-MW-mile costs, and higher voltage lines experience lower line losses.

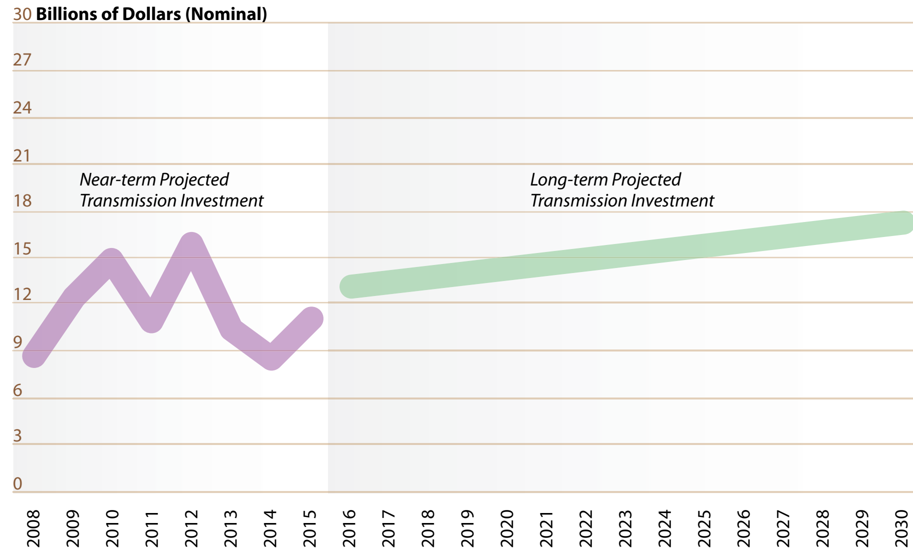
Within the Colorado context, it is not possible to make a reasonable cost estimate without knowing which GDAs

Transmission Investment by Investor-Owned Utilities (United States)



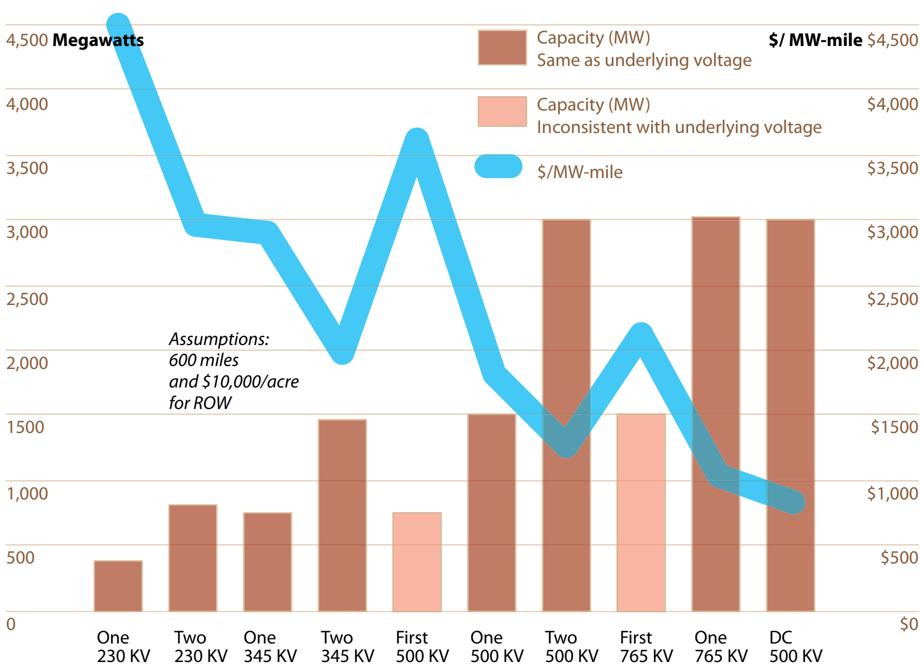
Source: Edison Electric Institute

Annual Transmission Investment Projections



Source: Edison Electric Institute

WREZ Transmission Cost Comparison



Source: Trans-Elect LLC

will be connected to the grid. That determination will depend upon what renewable energy projects developers propose, which proposals utilities select, what projects are least-cost, and, when appropriate as a regulatory matter, what the PUC approves. Although forecasting the future is by definition more art than science, the following observations can be made.

■ Large-scale wind plants, optimally sited and strategically integrated into the power system, provide a hedge against high natural gas prices. Natural gas prices have historically been quite volatile and have caused unsettling spikes in wholesale power costs in recent years.

■ Using current electric demand forecasts, Colorado will need new transmission and new generating capacity under any scenario.

■ Transmission costs in total account for less than 10 percent of a typical electricity bill. Under certain scenarios, the fraction for transmission could increase in the future above 10 percent, but it is unlikely to reach above 15 percent.

■ The Colorado Long Range Transmission Planning Group's research anticipates the need for between $525 million and $670 million in transmission infrastructure build-out by 2018, depending on different scenarios.

■ Under PSCo's current rates, transmission with a capital cost of $100 million amounts to 32 cents on the typical monthly residential bill.[78]

What are the potential benefits of transmission?

Texas has done more with transmission for wind power than any other area of the country. Texas has analyzed costs and benefits of various build-out scenarios. After an in-depth technical study by the Electric Reliability Council of Texas (ERCOT) of four finalist scenarios, the Texas Public Utility Commission selected a transmission build-out option that would accommodate more than 11,500 MW of additional wind power. ERCOT estimated the total capital cost of the transmission at nearly $5 billion. The average system fuel savings, however, was estimated to be $38 per MWh of additional wind production.[79] That amounts to a four-year payback period for the $5 billion transmission investment (discounting the stream of annual savings over time).

The low price of wind is predicated in large part to the $21 per MWh (in 2008 dollars) available to investors as a result of the federal production tax credit (PTC) for wind energy generation. Some note that renewable energy has relied upon subsidies, and this subsidy could change over time. By way of comparison, subsidies for other utility services[80] have prevailed for decades, despite many attempts to remove them. The history of the PTC has been particularly rocky because of the short timeframe placed on the PTC term. Similar term limitations attached to conventional energy subsidies are largely absent.

The Texas estimates of benefits are based on fuel cost savings. When a wind turbine puts an additional increment of energy onto the ERCOT system, it replaces the most expensive energy that otherwise would have been needed. (The market then clears at a lower price; all generators that are dispatched by ERCOT are paid the market clearing price.) The benefits also account for savings due to less line congestion. These estimates do not, however, include a price for CO_2 that could result from a possible cap-and-trade system. Adding a price for CO_2 to the ERCOT analysis could increase wind's net benefit and shorten the payback period for transmission.

A study of large-scale, long-distance transmission that would move wind power from the upper Great Plains to the East Coast similarly indicated benefit-to-cost ratios of approximately 1.7 to 1 for various scenarios.[81] The simulations, conducted by the Midwest ISO, PJM Interconnection and other Regional Transmission Organizations (RTOs) and major system operators, indicated that normally high location-specific wholesale power prices would fall in areas of New England and the Mid-Atlantic if transmission could deliver wind power into strategically located load pockets.

Whether similar cost savings are possible in Colorado depends upon several factors. Generally, system costs will be lower if the output of a large wind plant replaces the output of a fossil fuel plant that has a higher operating cost. This is most likely to occur when natural gas prices are high and during hours of the day when utilities would normally run large amounts of gas-fired generation. For the cost savings to occur in Colorado, the grid would need to be managed across a wider area to ensure the operation of the least-efficient fossil fuel units would be decreased when wind farms were producing. Throughout the eastern part of the country and in Texas, transmission systems are managed as large, integrated markets where units are dispatched on a least-cost basis several times within the hour. The Colorado system, by contrast, is both smaller and more fragmented among a number of controlling entities. This leads to systemic inefficiencies which, if addressed, could increase the expected benefits of new transmission.

A report produced for the DOE in February 2009, *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies*[82] found that "the total range in unit transmission costs for wind implicit in these studies is vast — ranging from $0/kW to over $1,500/kW. The majority of studies, however, have a unit cost of transmission that is below $500/kW, or roughly 25 percent of the current $2,000/kW cost of building a wind project. The median cost of transmission from all scenarios in our sample is $300/kW, roughly 15 percent of the cost of building a wind project. In terms of cost per megawatt-hour of wind power generation, the aggregate range of transmission costs is from $0/MWh to $79/MWh, with a median of $15/MWh and most studies falling below $25/MWh."

Transmission for Wind in Texas

New wind capacity	11.5 GW
Annual output (40 percent capacity factor)	40,500,00 MWh
Savings per MWh	$38
Annual savings (full wind build-out)	$1.5 billion
Discounted savings after four years	**$5.6 billion**
Capital cost of new transmission	**$5 billion**

Sources: Electric Reliability Council of Texas, National Renewable Energy Laboratory

Western Renewable Energy Zone Transmission Input Assumptions

VOLTAGE	CIRCUITS	CAPACITY (1) MW	CAPITAL (2) $000/mi	RIGHT-OF-WAY (3) width: feet	LOSSES (4) Per 100 mi	O&M+TAXES % Capital/YR)	SUBSTATIONS $MM/sub (5)	Spacing
230 kV - AC	Single	400	$900	150	6.90%	3.00%	$50	100 Miles
230 kV - AC	Double	800	$1,440	150	6.90%	3.00%	$50	100 Miles
345 kV - AC	Single	750	$1,260	160	4.50%	3.00%	$75	150 Miles
345 kV - AC	Double	1,500	$2,016	160	4.50%	3.00%	$75	150 Miles
500 kV - AC	Single	1,500	$1,800	175	1.50%	3.00%	$100	200 Miles
500 kV - AC	Double	3,000	$2,880	175	1.50%	3.00%	$100	200 Miles
765 kV - AC	Single	3,000	$2,250	200	1.00%	3.00%	$125	300 Miles
500 kV - DC	Bipole	3,000	$1,440	200	1.20%	3.00%	$250	Terminus

(1) Capacity limited by voltage of interconnecting lines
(2) Capital costs do not include right-of-way
(3) Values include both land and acquisition costs that vary by region and use which may range from $50K/mile to $650K/mile
(4) Losses calculated at full capacity
(5) Inclusive of transformer

Source: Western Governors' Association

Proposed New Colorado Transmission Projects to the Year 2018

TRANSMISSION PROJECT	VOLTAGE LEVEL (KV)	COST ($M)
Energy Center2-Burlington	500/345	70
Energy Center-Burlington-Big Sandy–Road 125-Missile Site	500/345	160
Energy Center-Comanche	500/345	80
Energy Center – Lamar	230	10
Lamar - Vilas	230/345	30
Pawnee-Daniels Park & Smoky Hill –Daniels Park	345	65
Ault – Cherokee	230	65
Wyoming – Colorado Intertie	345	+
San Luis Valley – Calumet	230	115
Calumet-Comanche	345	65
Calumet-Walsenburg	230	0
TOTAL		**670**

** The costs represent 2008 dollars and are considered to have +/- 30% accuracy*
+ Estimated cost of above $200 million
Source: Colorado Long Range Transmission Planning Group, 2009

Can we estimate the cost and benefits of a major increase in utility-scale renewable energy generation and high-voltage transmission?

Colorado will need new power plants and new transmission lines in most plausible pathways of the state's electric power industry. Exceptions could be zero-net load growth due to reduced customer use, caused either by macro-economic conditions or a major policy commitment to demand-side resources. Maintaining reliability and ensuring a strong economy in an increasingly electrified environment requires increased investment levels. With steady population growth through 2020 and beyond, Colorado faces large-scale generation, transmission, and distribution investment choices among many options. Thus, costs will increase in any case. The question for broad public discussion is how the costs and benefits of a proposed pathway that relies heavily on renewable energy and high-voltage transmission to meet the 20x20 goal compares with those of other choices.

To provide additional cost information, we offer the chart above from the Western Governors' Association Western Renewable Energy Zones Project:

The table at the top of this page summarizes the cost of several specific transmission proposals developed by the Colorado Long Range Transmission Planning Group in their January 2009 report, *2008-2018 Transmission Planning Study.*[83]

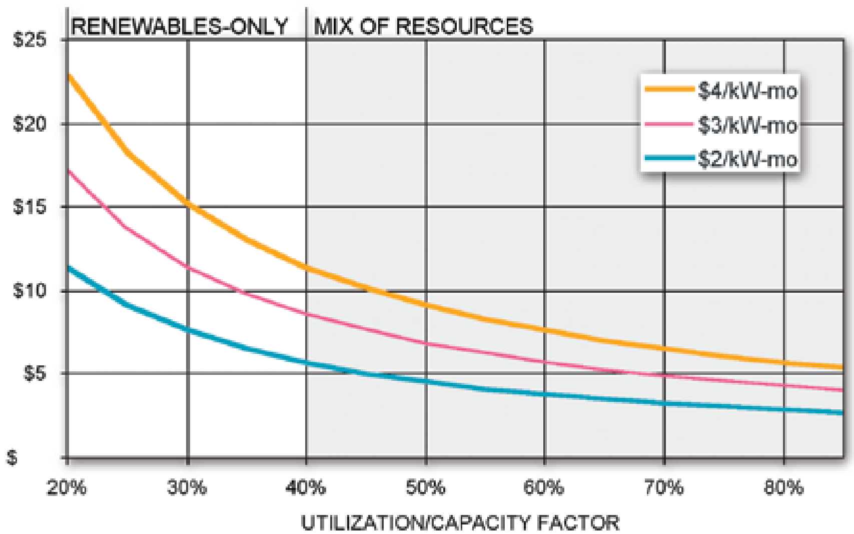
Is it practical for a transmission line to be built exclusively for transmission of renewable energy?

Technically, the answer to this question is yes; practically, the answer is no. Nearly all transmission in the nation is under Federal Energy Regulatory Commission (FERC) jurisdiction, and a core FERC regulatory principle is "open access" to transmission. Under strict application of this principle, a transmission owner such as PSCo or Tri-State could not deny a fossil plant operator's right to connect to a line the utility had built to a renewable GDA. However, no corresponding requirement exists for PSCo or any other load-serving regulated utility in the state to purchase the output of the proposed fossil plant. Without a long-term purchase commitment — or similarly, PUC approval of the fossil plant for inclusion in PSCo's electric resource plan — a new coal plant would be speculative, risky, and in all likelihood would not be economically feasible. Even if a prospective power purchaser were out of state (and

Other Colorado Coordinated Planning Group Bulk Transmission Projects Planned for the Year 2018

TRANSMISSION PROJECT	ENTITY	IN-SERVICE DATE	COST (M$)*
Comanche-Daniels Park 345 kV	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	PSCo	2012	35
Pawnee – Smoky Hill 345 kV	PSCo	2013	130
Burlington – Wray 230 kV	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*
Source: Colorado Long Range Transmission Planning Group, 2009



Source: Trans-Elect LLC, from the SB07-91 Report, page 57

therefore beyond the jurisdiction of the Colorado PUC), the ability to export the power would be limited by transmission constraints elsewhere on the system.

Siting of a line to a GDA also may geographically favor the renewable resource that defines the GDA. Unlike a wind farm, a new coal- or gas-fired plant would need access to water and to rail or pipelines to deliver fuel to the remote site. Thus, nature itself may impose a *de facto* limit on the ability of a new fossil fuel plant to use a transmission line built to serve a renewable energy GDA.

Even so, mechanisms exist by which Colorado could further ensure renewable resources are never crowded off a transmission line to a renewable GDA. FERC has acknowledged that location-constrained renewable resources pose special transmission problems, and that a utility can create special tariff provisions to accommodate these resources.[84] Colorado can devise its own approach, subject to FERC approval. Elsewhere in the country, transmission owners are experimenting with an "anchor tenant" model in which one or more major renewable energy projects would have an equity ownership in a portion of a new line to which it would have exclusive rights. FERC has endorsed the anchor tenant model for two major transmission projects in the West. The first is a 1,000-mile, 500-kV high-voltage direct-current transmission line from Harlowtown, Mont., to a point south of Las Vegas, Nevada. The second is a 1,100-mile, 500-kV high-voltage direct-current transmission line from Medicine Bow, Wyo., to a point south of Las Vegas, Nev.[85] Closer to Colorado, owners of the proposed Wyoming-Colorado Intertie Project have auctioned access rights to the line; both winning bidders were wind developers.

Wind and solar resources typically have capacity factors of between 30 percent and 45 percent. The energy produced as a result of the wind and sunshine that actually occurs is 30 percent to 45 percent of energy produced if the equipment were generating at full capacity all the time. This affects utilization rates of transmission lines connecting renewable resources to the grid. Unless the transmission line is, where possible, shared with flexible resources that can be increased or decreased in relation to opposite natural changes in wind or solar output, line use will be lower, and the cost of the line per MWh delivered to customers will be greater. The chart above illustrates this concern.

II. Where We Are Today

This section examines the current state of Colorado's transmission system and its wholesale electricity market. It is divided into two broad sections: 1) the context for transmission in Colorado, concluding that the lack of transmission facilities built to bring power from GDAs to major load centers is a significant issue for the state; and 2) transmission policy issues for Colorado.

Colorado's Transmission Context

How is transmission relevant to economic development, renewable energy development, job creation, and environmental quality?

Transmission is a connector. Colorado possesses vast wind and solar resources. These resources will serve a societal purpose when that energy is delivered by high-voltage transmission to substations and lower voltage distribution systems to serve loads (the places where homes, businesses or others use electric power). It is widely understood in Colorado that the existing transmission infrastructures in most of the GDAs identified in the *SB07-91 Report* are insufficient to deliver high levels of new clean generation from renewable resource-rich rural areas to the markets, mostly along the Front Range. Progress is being made by industry groups, nongovernmental organizations and others to shore up these insufficiencies through work at the PUC, in regional planning venues, in the legislature, and elsewhere.

Current efforts underway to develop Colorado's transmission infrastructure are showing some improvements in several areas. If SB07-100 were to be fully implemented, Colorado would benefit from the new infrastructure's ability to deliver reliable, sustainable electric supply through new high-voltage transmission facilities. If delays develop, however, Colorado will fall short of realizing the full economic, employment, reliability, and environmental benefits on the horizon.

Coloradans favor achieving the benefits that come with new renewable energy manufacturing in the state, and those that result from wind and solar projects in rural Colorado. The value of addressing the combined utility-scale renewable energy and transmission opportunities are wide-ranging. They include royalties that farmers and ranchers earn from hosting wind turbines and solar farms on their property. In the case of wind farms, payments of upward of $5,000 per wind turbine per year are typical. Benefits also include a surge in local tax receipts. Areas such as Prowers, Bent, Logan, Weld, and Sedgwick counties have seen major local increases to their tax base stemming from wind project development.

Although new opportunities are apparent, renewable energy development and transmission infrastructure improvements also face many identifiable challenges. These include, but are not limited to, increasing the level of consensus in resource planning, working to overcome financing hurdles, addressing the often-contentious issues related to cost allocation and cost recovery, planning and investing for new transmission, addressing integration of naturally variable renewable resources, transmission siting, and improving dispatch practices. Better coordination is also needed among developers, lands and wildlife groups, and the Colorado Division of Wildlife, to ensure natural resource considerations are addressed early in generation and transmission planning.

What is the mix of resources available to meet society's electric power needs?

Colorado currently uses a portfolio of strategies to meet its lighting, cooling, heating, plug-load, industrial and other electric power needs. These strategies include both supply-side sources and demand-side sources. Supply-side sources include central station fossil-

Colorado GDAs do not have sufficient transmission to deliver significant amounts of renewable energy to major load centers.

fuel plants (primarily coal and gas), utility-scale wind and solar, hydroelectric resources, distributed generation (such as on-site photovoltaics), and transmission. Colorado's electricity sector currently depends heavily upon fossil-fueled generation to serve end use electric needs. Demand-side sources include conservation, load management, and on-site energy efficient equipment and techniques.[88] Supply-side and demand-side approaches have different costs, operating characteristics, emissions and transmission needs. Although each has unique challenges, the most cost-effective approach in general is to maximize deployment of demand-side resources.

Who decides what mix of resources to deploy?

Colorado's utilities, regulators, elected policy makers, industry trade associations, environmental organizations, consumer associations, and many others all have roles in helping to influence what mix of resources to deploy. These entities work in various ways to identify the most cost-effective, environmentally sustainable, and long-term methods to combine and balance resources to meet the state's present and future electric power needs. It should come as no surprise that these groups do not always agree on what assumptions to use when planning future energy needs.

The task confronting decision makers is referred to as electric integrated resource planning (IRP) or electric resource planning (ERP). Colorado IOUs (PSCo, and Black Hills Energy) propose a portfolio of both new demand- and supply-side resources to the PUC. After a public hearing and stakeholder input, the PUC can modify utility plans and direct the utilities to acquire a portfolio of resources through a combination of competitive and utility-sponsored processes that represent a certain fuel mix. Governing boards or city councils make the primary decisions for rural electric cooperatives, generation and transmission associations, and municipal utilities. Should the IOUs and Tri-State want to construct either large generation or transmission projects, the PUC must first approve their applications for a CPCN. A summary description of the Colorado electric power industry is located on page 37 of the *SB07-91 Report*.

Colorado has identified renewable resource GDAs. Do these GDAs have sufficient high-voltage transmission?

Colorado GDAs do not have sufficient transmission to deliver significant amounts of renewable energy to major load centers. Although some GDAs have lower-voltage and some have higher-voltage transmission, these lines were not designed to deliver major blocks of wind or solar power to the markets. While Colorado's transmission-owning utilities and wind developers are building new lines, for various reasons the expansions to date have not followed a strategic plan. Thus, the *ad hoc* expansions risk not fully capturing the long-term benefits that renewable energy generation is expected to play in Colorado's carbon-constrained electricity sector. The map to the right shows Colorado's high-voltage network superimposed on the GDAs. It illustrates how few high-voltage lines serve the renewable resource GDAs.

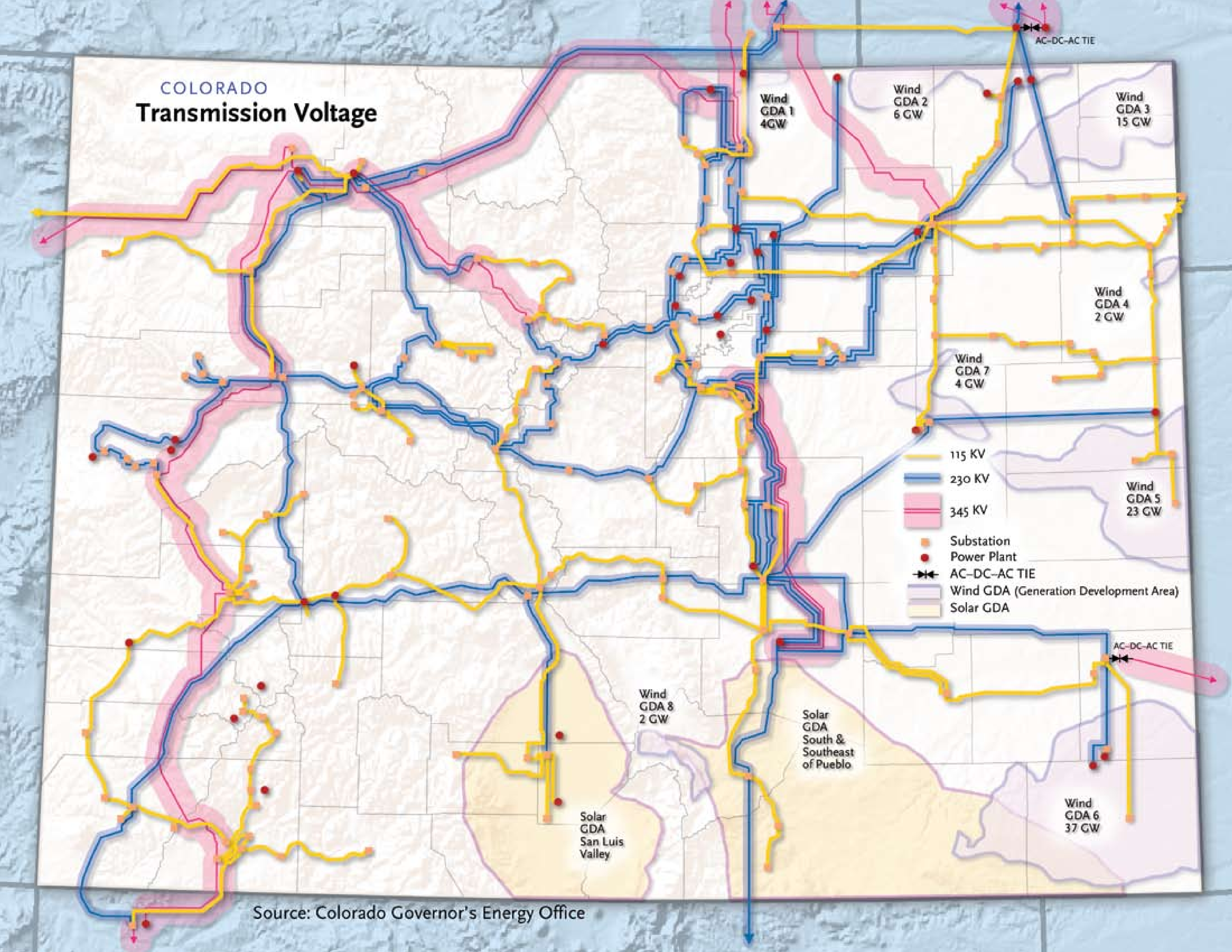
Should there be delays in the construction of planned transmission to the GDAs, the result may increase the cost of renewable energy to Colorado customers. Building lines *ad hoc* to scattered renewable energy projects may result in more lines encroaching on more open space. Transmission built *ad hoc* will likely tend to be lower voltage than optimum, resulting in higher line losses. In the alternative, consolidating capacity on a single line of higher voltage will increase transmission efficiency and reduce losses.

- Competition among developers will suffer, resulting in fewer and more expensive choices for new renewable resources; transmission to a GDA would establish the GDA as a competitive space with reduced uncertainty about transmission, and this would likely increase the number of developers competing for interconnection.

Is Colorado's transmission system already constrained and do those constraints affect the ability to build and integrate new renewable generation?

Both the Colorado Task Force on Reliable Electricity Infrastructure and the Colorado Energy Forum have pointed out the significance of Colorado's transmission constraints. The Colorado Task Force on Reliable Electricity Infrastructure, established by Colorado House Bill 06-1325, states in its Nov. 1, 2006, report:

"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


COLORADO
Transmission Voltage
Wind GDA 1 4GW
Wind GDA 2 6 GW
Wind GDA 3 15 GW
Wind GDA 4 2 GW
Wind GDA 7 4 GW
Wind GDA 5 23 GW
Wind GDA 8 2 GW
Wind GDA 6 37 GW
Solar GDA South & Southeast of Pueblo
Solar GDA San Luis Valley
AC–DC–AC TIE
115 KV
230 KV
345 KV
Substation
Power Plant
AC–DC–AC TIE
Wind GDA (Generation Development Area)
Solar GDA
Source: Colorado Governor's Energy Office

Although the new renewable energy generation built to date in Colorado has been able to connect to the existing transmission system, the system is close to meeting its physical ability to accept injection of new utility-scale renewable energy generation.

transmission to meet the needs."

The Colorado Energy Forum described Colorado's need for transmission as follows:

"Transmission is ... a missing link that threatens to lead the state to a genuine energy crisis. Colorado's capacity to move electricity from where it is generated to where it is used is constrained. In short, we need more electric transmission capacity, and we need it soon. Failure to upgrade existing transmission lines and to deploy new transmission infrastructure in Colorado could have severe and long-lasting consequences for the state — not the least of which is an inability to put online the large amounts of new renewable resources that the public desires."

Colorado's transmission system is not sufficiently built out to serve areas that can produce large blocks of renewable power. The system lacks the capacity to handle a large new injection of power that would result from several thousand megawatts of new generation. Colorado's current transmission system cannot deliver the amount of new renewable energy generation to meet the 20x20 goal.

It is beyond the scope of this report to provide specific recommendations for the amount of new high-voltage transmission needed. For instance, Available Transmission Capability (ATC) is one important measure that would determine requirements for new transmission to support new generation. Because ATC levels on any given line varies hourly, daily, or seasonally, it is not possible here to identify ATC on lines.

Although the new renewable energy generation built to date in Colorado has been able to connect to the existing transmission system, the system is close to meeting its physical ability to accept injection of new utility-scale renewable energy generation. A REDI Project contractor (Navarro-E2MG) documented in its *Colorado Generation and Transmission Baseline Assessment (CGTBA)* report that PSCo has sufficient ATC on its system to interconnect an additional approximate 1,500 MW of new capacity. This may be changing, as PSCo, through its SB07-100 process, plans to accommodate more than 5,000 MW. The *CGTBA* reports that Tri-State has no ATC to handle injection from new generation. Thus, any major new generation, renewable or otherwise, that requires high-voltage transmission service would require that Tri-State build new transmission. Tri-State is addressing this issue, in part, with the proposed construction of the San Luis Valley-Calumet-Comanche line and other planned facilities, as detailed later in this report.

Why is Colorado's renewable energy development not happening faster?

Despite the many benefits that renewable energy brings to customers, to the economy, and to the diversification of Colorado's power system, the pace of renewable energy development is limited by lack of transmission. To address the transmission limits, public policy and utility system planners must continually deal with several challenges, including, but not limited to the following:

■ *The highest quality renewable generation resources in Colorado are remote from the loads.* This is generally the situation nationwide, as discussed earlier. Colorado's electric loads are concentrated along the I-25 corridor, and the renewable resources are primarily located in far reaches of the eastern half of the state, in the southern part of the state, and in some adjoining states.

■ *Costs.* The cost of power plants is measured in two broad areas — their initial capital costs (expressed in dollars per installed kilowatt capacity), and operations and maintenance (O&M) costs (inclusive of fuel costs). When considering the delivered cost of electricity, transmission costs are added to generation plants costs. Generally, the farther the generation location, the higher the transmission investment is needed to deliver it to loads. Good generation sites can bear their transmission costs — witness the "extension cord" approach for wind plants — and still save electric customers money when the generation is added to the system. For more information see the detailed technical studies prepared for this report conducted by the UCD study, available on the REDI page on GEO's website.[89]

■ *To date, initial capital costs are higher for renewable power plants than for natural gas power plants.* The trend line for renewable power plants, however, is on a downward curve. Capital costs per installed kilowatt capacity are lower for wind generation than for coal-fired power plants, and are significantly lower than for either commercial advanced coal plants (such as Integrated Gasification Combined Cycle) and nuclear power plants. Wind plants have no fuel or water costs, but do have moderate O&M costs. The initial capital costs of concentrating solar power (CSP) plants are comparably higher than wind and gas plants. However, CSP plants have the benefit of little or no fuel costs, and can address water consumption if they use dry cooling technology.

The solution may be to build transmission to renewable resource GDAs, where the economic prospects are so compelling that developers would compete vigorously for the opportunity.

■ *Utilization factors for renewables generally are lower than for some fossil resources.* Wind power plants provide energy into the power system when the wind blows and absent co-located gas resources, will use the transmission system at their rated output for only 30 percent to 40 percent of the time, depending on the quality of the particular wind resource, although they might generate some power 80 percent or 90 percent of the time. For comparison, building transmission exclusively for a wind resource is a less efficient use of that transmission than a coal-fired generating station that should be expected to produce power at its rated maximum output an average of about 85 percent of the time. That said, however, all utility systems accommodate a wide variety of resources that serve different functions on the power system. Some natural gas plants act only as "peaker" plants; they operate only a few hours each year during the peak periods of the day or year. In addition, if one wind facility's output can be planned and managed jointly with complementary wind, natural gas or other generators' overall utilization factors on the transmission system improves.

Utilization factors for CSP plants are higher than for wind in part because they can be built with up to six hours of storage so they can continue to produce electricity for several hours after the sun sets. When feasible, gas plants could be co-located with CSP plants to boost the thermal output when direct solar radiation is not available. This will increase the utilization factor of the transmission system connected to the CSP plant.

■ *Siting and permitting.* It is often difficult to site transmission lines. Developers may need to obtain multiple permits from several levels of government, ranging from county to federal. If transmission lines cross private land, developers must secure permission from many individual landowners. This task may be eased somewhat when the transmission is developed by utilities, which are granted the power of eminent domain that ensures that a "public good" such as a transmission line cannot be blocked by landowners.

■ *Transmission constraints.* The transmission system currently is not built to deliver power from Colorado GDAs. The present system can not handle injection of the energy generated by several thousand MWs of new renewable energy resources, should that amount be needed to reach the 20x20 goal, as suggested by the UCD modeling.

Colorado Transmission Policy Issues

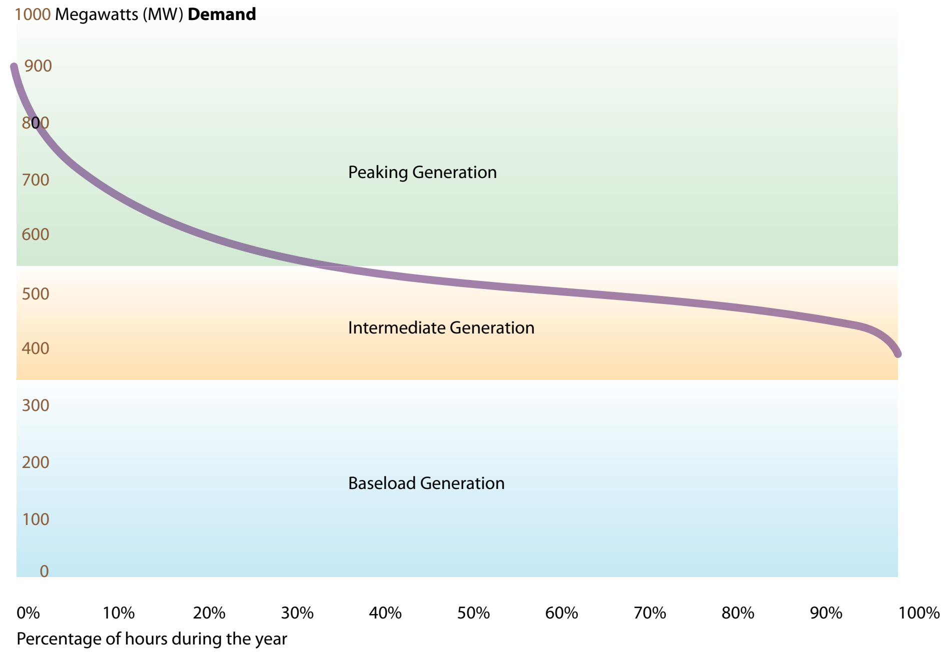
Transmission presents a policy dilemma. Unless adequate transmission is available, a new utility-scale renewable energy project is less likely. Without greater certainty that a new renewable power project will be developed, new transmission may not be planned, or may not be approved. A few projects may proceed where transmission capacity is available on the existing system, but such opportunities are becoming increasingly limited.

The solution to the dilemma may be to build transmission to renewable resource GDAs, where the economic prospects are so compelling that developers would compete vigorously for the opportunity. Texas, which pioneered this approach, leads the country with nearly 9,000 MW of wind power and is building new transmission that would more than double that amount. To obtain such results, however, Texas changed its transmission planning and approval laws. Because Texas operates in its own balancing authority area outside of federal jurisdiction, it is better able to control its destiny.

The challenges are greater for Colorado because many of the state's transmission challenges are regional. In the Western Interconnection (the "western grid"), greater integrated coordination of renewable energy and transmission policy is underway. At present, the Western Interconnection is divided into 37 balancing authority areas.[90] There are two balancing authorities in Colorado - one operated by the Western Area Power Administration (Colorado-Missouri Region), the other operated by PSCo. A stronger emphasis on coordinated planning is expected to lead to lower costs and faster deployment. As a result, electric customers would receive long-term economic and environmental benefits from early commitments to utility-scale renewable energy development. Major transmission planning activity is now under way to achieve these results, assisted in large part with financial support from the DOE's Office of Electricity.[91]

Through the SB07-91 mapping exercise, Colorado made an important start by identifying its best GDAs for wind and solar power. Colorado also initiated the SB07-100 process to address transmission planning related to cost recovery and identification of transmission development to beneficial ERZs. Several policy questions remain to be addressed, including, but not limited, to those that follow:

The Role of Various Types of Generation



Source: PSCo's 2007 Colorado Resource Plan

- What are the roles and functions of different types of generating resources in the overall power system?
- How does transmission planning pose a challenge?
- From an engineering standpoint, how difficult is it to replace high-carbon resources with zero-carbon resources?
- What are the characteristics of the current wholesale electricity market in Colorado?
- What proposals now exist to significantly expand interstate transmission?
- How competitive is Colorado's wholesale power market?
- Other areas of the country have centralized markets for wholesale power transactions. Does Colorado?
- What does this mean for renewable energy development?
- How are other states meeting renewable energy goals?
- How are Western states identifying the location for the best renewable energy resource developments?
- Colorado has more renewable energy potential than it needs. What are the opportunities to export it?
- What is rate pancaking?

The remainder of this chapter addresses each of these questions in turn.

What are the roles and functions of different types of generating resources in the overall power system?

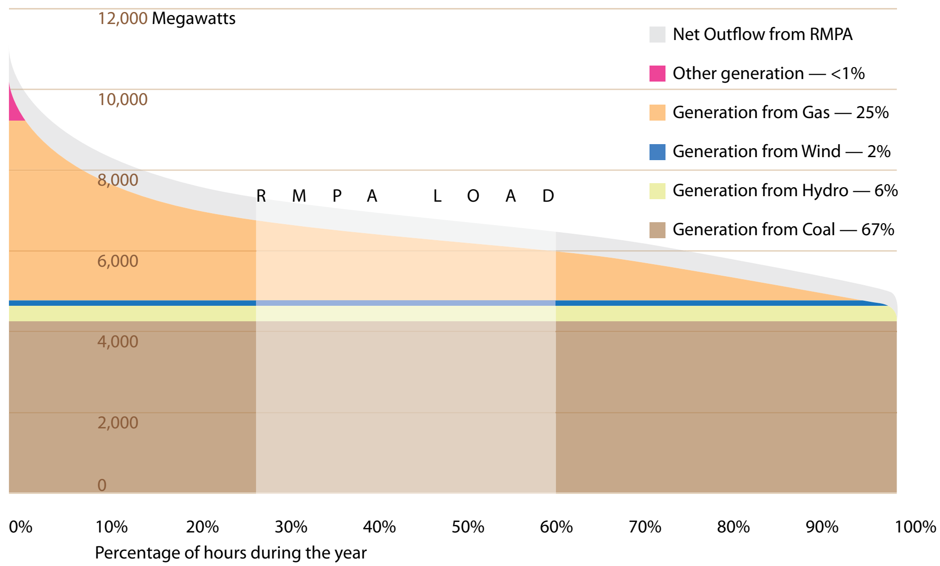
Two types of resources are available to Colorado electric utilities for meeting demand and energy requirements of their customers. Supply-side resources provide generation capacity and transmission to serve load, and demand-side resources help to reduce the level of customer demand for electric power so fewer supply-side resources are necessary. Supply-side resources generally are categorized as traditional (fossil thermal, nuclear, and large scale hydro) and renewable. Conventional supply-side resources are typically fossil-fuel based generation resources that require a steady fuel supply. In contrast, supply-side renewable resources are generation resources that are abundant, are free of fuel costs, are locally available, and are clean.

Conventional supply-side resources generally are represented by peaking, intermediate and baseload units. Peaking units usually are combustion turbines that operate in simple cycle using natural gas as fuel. Combustion turbine units are available in a wide range of sizes (25 MW to 300 MW). Peaking units' principal role is to run for a few hours of the year typically during the highest electric demand hours, since the turbines have rapid ramp rates of usually less than 10 minutes. (Ramp rate refers to the amount of time it takes to bring a power plant to, or drop, its production from its rated output level.)

Combustion turbines are relatively inexpensive, in terms of capital construction costs. They are relatively inefficient (i.e., they use considerable amounts of fuel per unit of output or "have a high heat rate"), however, and operating costs are high. Because the turbines are expensive to run, they operate only a few hours annually.

Intermediate units generally are combined cycle units. These generators are more efficient natural gas-fired facilities that could use single or multiple combustion turbines in conjunction with a heat recovery steam generator (HRSG). The waste heat from combustion turbines' exhaust gas is used to generate steam through a HRSG to run a steam turbine that, in turn, produces additional electric power. Combined cycle units can be quickly increased or decreased, and they come in various sizes (100 MW to 700 MW), depending on the facility configuration. Combined cycle units cost more to build than combustion turbines, but their operating costs are lower due to higher efficiencies (i.e., lower heat rate). Since both combustion turbines and combined

Rocky Mountain Power Area (RMPA) Annual Net Generation Fitted to Load Duration Curve



Note: Annual generation is distributed evenly for ease of illustration; chart does not reflect real-time fuel use. Fuel quantities under the supply curve are proportional to total generation; net outflow is the amount of generation in excess of RMPA demand.

Sources: Energy Information Administration, Electric Power Monthly (EIA-923 database); SNL Financial, Planning Area Load Duration Curve, Rocky Mountain Power Area, 2007).

cycles use natural gas to generate power, their production costs or delivered price of electricity, are determined largely by the cost of natural gas, which has historically been quite volatile.

Baseload units are designed to run continuously except when they are shut down for scheduled maintenance. An unexpected halt of operations is called a "forced outage." Baseload units have the highest construction costs, but have the lowest fuel costs. Since they are not designed to cycle, baseload units such as coal and nuclear power typically have much lower ramp rates compared to combustion turbines and combined cycle units. Hydropower is the ultimate peaking resource; ramp rates are as fast, or faster than combustion turbines.

The chart on the preceding page, sourced from PSCo's 2007 Colorado Resource Plan, illustrates the role of various types of generation.

Operating cost characteristics vary among fossil generation technologies (peaking, intermediate, baseload). These characteristics dictate how these technologies are economically dispatched to serve system load requirements. The Rocky Mountain Power Area graph on this page provides a general overview of electricity generation. The shape of the curve (the portion comprising all generation other than net outflows) shows how often total electricity demand reached a certain level in 2007. Demand never fell below 4,300 MW even in the middle of the night. Half of the time, demand was 6,300 MW or less. The highest hourly average demand was 10,394 MW. This means that at any point in time the system needed to accommodate 10,394 MW of generation, plus an additional margin of reserves that could be called on in case a generator or transmission line somewhere on the system failed unexpectedly.

Coal provides most of the area's baseload requirement. It generally corresponds to the 67 percent of total demand indicated as the base of total generation in the figure below. These plants normally run all the time (except for planned outages for maintenance, or forced outages) at a constant level. Because natural gas units can be turned on, up, down, and off more easily and at less cost than coal units, they can better respond to fluctuations in demand and the need to integrate naturally variable resources.

How does transmission planning pose a challenge?

Ever-increasing peak demand strains the transmission system's weakest points first. Addressing these critical reliability needs will remain the top concern for transmission planning. Traditional transmission planning has done an exceptional job in reliably matching projected load growth with generation. Planners also work to anticipate these growth-related reliability issues five to 10 years in advance. When growth forecasts point to the need for new generating resources, the primary aim for transmission planners is to ensure reliability. Traditionally, transmission planners may have focused less heavily on the environmental performance of added resources as long as there is a balance between baseload, intermediate, and peaking resources.

Does the advent of concerns about carbon dioxide change planning requirements?

With the advent of concerns about CO_2 emissions, planning tasks change for both generation and transmission. Of course, planners will always need to concentrate primarily on ensuring enough generation and transmission to meet total demand at the time of peak electric system use, a concern about the capacity of the system to meet loads. With CO_2 concerns, the planners also will be concerned about the total amount of CO_2 emitted. The planning focus will increasingly include the question of what

It would be advantageous for future CCPG planning to consider calculating CO_2 reductions in its scenarios. In so doing, transmission planners will help create a future that is more independent of fuel price escalation and the effects of CO_2 regulation.

generation to consider, given that CO_2 levels vary considerably from one generation choice to the next.

Sometimes called "energy-first planning," this new planning idea suggests that planners first incorporate as much non-carbon, or low-carbon generation or demand-side measures as possible, then fill in with the lowest carbon- emitting capacity resources required to meet capacity or total load requirements.

This new energy-first planning criterion is consistent with how electric systems incorporate renewable energy — because renewable energy projects' costs are almost entirely capital. There are no fuel costs (except for biomass projects), so, energy from these projects is produced at very low cost. In energy-first planning, renewable energy projects are included first in the dispatch order for generators (this is called "must-take" or "must-run") so the low-cost energy can be used before dispatching generators that have additional fuel costs. Thus, wind displaces natural gas generation whenever wind is available and gas generation can be turned off or turned down at a savings to electric customers.

The most recent transmission planning in Colorado was conducted by the Colorado Long Range Transmission Planning Group (CLRTPG), a subset of the Colorado Coordinated Planning Group (CCPG). In the most recent CLRTPG plan, released in January 2009, the group reported it used the following planning principles:

1. Identify "backbone" or "bulk" transmission plans that will reliably meet forecast load requirements and accommodate a variety of potential resource plans.

2. Quantify the potential costs of the transmission plans.

3. Jointly perform studies and coordinate with other Colorado Coordinated Planning Group planning activities.

4. Adhere to the planning principles set forth in FERC Order 890, including conducting joint studies in a coordinated, open and transparent manner.

5. Comply with North American Reliability Corporation (NERC) Standards and WECC Criteria.

6. Efficiently use transmission corridors by proposing to use existing corridors where feasible, and reasonably size the capability of new corridors.

Changing Colorado's electricity sector with the additional objective of reducing CO_2 emissions — as contemplated in the 20x20 goal, and in the scenarios used in this report — has not yet explicitly been an objective of transmission planning as practiced at the CCPG and the CLRTPG. Because the CLRTPG studies included two renewable energy development scenarios, the 20x20 goal was addressed, although not directly.

It would be advantageous for future CCPG planning to consider calculating CO_2 reductions in its scenarios. Incremental changes are evident in the generation and transmission planning paradigm, which gives rise to anticipation that a new transmission planning focus is on the horizon in Colorado. The new focus will likely result in detailed engineering analyses of how to best integrate utility-scale renewable energy at the maximum feasible operational and economic levels. In so doing, transmission planners will help create a future that is more independent of fuel price escalation and the effects of CO_2 regulation. This future points to major challenges for planning and operating the transmission grid in Colorado. These challenges include:

- Scaling back high-carbon generating plants and partially replacing them with generation from new zero-carbon plants (such as wind, solar or geothermal energy) may change use of an existing transmission system and, when considered, must do so without risking system reliability. Transforming a system that previously was used primarily to transmit power from fossil-fired baseload units to one that transmits a mix of resources that produce power at different times of the day — and may ramp up or down quickly (thus requiring integration of complementary gas power plants, storage or other measures) — will require different planning, building, and operating methods for both generation and transmission systems. Traditional planning that focuses almost exclusively on reliability and access to generating resources — and only minimally on scenarios to integrate zero-carbon resources — may not naturally search for new ways to integrate low-carbon resources onto the transmission system.

- Minimizing financial costs, risks, and liabilities to electric customers. To more quickly move Colorado's electric power system from high-carbon to a mix of resources that includes an ever-higher fraction of zero-carbon generation resources may suggest a longer planning time frame than the 10 years used for traditional generation resources. Further, integrating transmission planning with longer-term planning for CO_2 reductions requires longer than the current 10-year transmission planning time horizon. Transmission assets have lives of approx-

Transmission and renewable energy planners struggle with what they call the "chicken or egg" problem — which comes first: transmission or generation?

imately 40 to 60 years, and longer with scheduled maintenance and upgrades. Wind and solar resources delivered to the market by new transmission will not be depleted. Transmission will be injected with output from increasingly sophisticated wind turbines and solar generators that operate with little concerns regarding future fuel, water, and carbon regulation liability costs.

■ Transmission and renewable energy planners struggle with what they call the "chicken or egg" problem- which comes first: transmission or generation? Future low- or no-carbon generation will require agreement about where the new resources will be developed, perhaps without knowing which developers will build them. In traditional transmission planning, new lines are added in conjunction with new generating plants that have been financed and approved, and that usually are on a similar construction schedule as the transmission. Some have suggested that in the new planning context, the best generation resources need transmission before they can be developed: transmission may need to be provided on a "build it and they will come" basis. The Texas CREZ experience suggests the merits of this approach.[92] Because others disagree with this proposition, deeper analysis of this approach is all but certain to take place.

Common to all these challenges is the fact that the issues usually can be more easily and cost effectively addressed if the planning territory is large and diverse and if the planning is far-sighted to allow plenty of time to consider in advance all options and to change or correct course if necessary. Today's 10-year transmission planning is barely "just in time" given the long lead time necessary to plan, justify, get permits, and construct new transmission. Some in Colorado suggest that 10-year plans are "not quite in time." Large areas that incorporate diverse options and planning over several decades allow more options to be considered in the study. Because approval and construction of new lines to preferential zero-carbon resources can be more fully anticipated, required investments could be expedited. Institutional venues already exist for multi-utility, multi-jurisdictional transmission planning. Clear policy directives to guide planning objectives, and the legal weight afforded to planning outcomes once regulatory review and approvals begin, are critically needed to effectively guide these planning decisions.

What are "independent transmission companies" and what role do they play—or could they play—in Colorado?

Independent transmission companies (ITCs) are a relatively new class of transmission owners/operators facilitated by FERC policy in 1999. In contrast to traditional vertically-integrated utilities, ITCs focus solely on transmission since they are precluded by FERC policy from participating in power markets. ITCs compete with traditional utilities to promote low-cost transmission options to meet reliability and delivery requirements.

ITCs are active throughout North America, with several merchant transmission projects developing within the West. In Kansas, ITCs have been provided opportunities where vertically integrated utilities have abdicated their responsibility for expanding transmission — an opportunity that International Transmission Company has taken advantage of. ITCs had the opportunity to competitively bid on the CREZ transmission projects in Texas and three ITCs received awards for building approximately 30 percent of the $5 billion CREZ transmission build-out. ITCs sometimes work in partnerships with traditional utilities. The successful Path 15 project in California, for example, was completed in 2004 by Trans-Elect Development (an ITC) in partnership with WAPA and PG&E.

Transmission competition is limited in Colorado because no provisions exist for ITCs in Colorado statute, within the PUC, or in the non-RTO portions of the WECC. Currently, for ITCs to be successful in Colorado, they or their shippers must contract with the very utilities with which they would attempt to compete. Thus, most ITCs have not participated in Colorado transmission activities nor have they pursued projects within the state. One suggested potential public policy option would amend Colorado's transmission statutes, including SB07-100, to allow more equal competition by including ITCs in the Colorado marketplace.

The map that follows shows the ownership of high-voltage (115 kV and above) transmission lines in Colorado. The map does not indicate voltage levels.

From an engineering standpoint, how difficult is it to replace high-carbon resources with zero-carbon supply-side resources?

The most important difference between operating a fossil-fuel plant and a wind farm or solar farm is the ability to control output. A controllable resource can be easily planned to match the next day's anticipated demand: with real-time demand itself being the only source of uncertainty. A sophisticated demand-response program can greatly reduce the effects of this uncertainty and can limit associated generation needed to meet demand fluctuations.

The best an electricity system operator can do with a non-dispatchable resource is to forecast the next day's wind or sunshine, combine the forecasted output with the load forecast, and schedule a dispatchable resource (typically a gas plant, but future potential resources could include large batteries, additional pumped hydroelectric storage, compressed air energy storage, or other devices) to cover the balance. Non-dispatchable resources introduce new uncertainty in addition to the normal variations in balancing real-time load with generation. Electric utilities, NREL, and others are conducting significant work to address this challenge, with the goal of achieving 15-minute forecasting.

Integrating higher penetrations of wind and solar resources into the system is another fundamental operational challenge, even after the basic challenge of transmission availability is addressed. As with transmission planning, the challenge of wind integration is somewhat less daunting when it can be addressed over a large, diverse geographic area. A 119-page wind integration report produced for PSCo in 2006,[93] in response to a requirement by the PUC to conduct such a study, provides detailed estimates of the additional ancillary costs to integrate wind at 10 percent, 15 percent, and 20 percent penetrations. NREL is at the forefront of efforts with industry partners to address the wind integration challenge.[94] In addition, a 118-page report by the California Institute for Energy and the Environment Transmission Research Program, *Technology Research for Renewable Integration*, provides those who follow this topic with valuable detailed analyses.[95]

Xcel Energy is partnering with the National Center for Atmospheric Research and NREL to use a highly detailed, localized weather forecast system to assist with an advanced wind prediction system. The intended result is to develop mathematical formulas from NREL that calculate the amount of energy that turbines generate when winds blow at various speeds. If successful, the project will improve a utility's decision-making ability to increase wind energy penetration.

Per system, the total amount of electricity demand from one moment to the next is both variable and uncertain, so utilities always keep a certain amount of reserve capacity on hand. The reserve capacity on any given generator is the difference between the unit's maximum operating limit and its current operating level. It is the additional amount of output the utility can dispatch at a moment's notice from units that already are online and producing power.

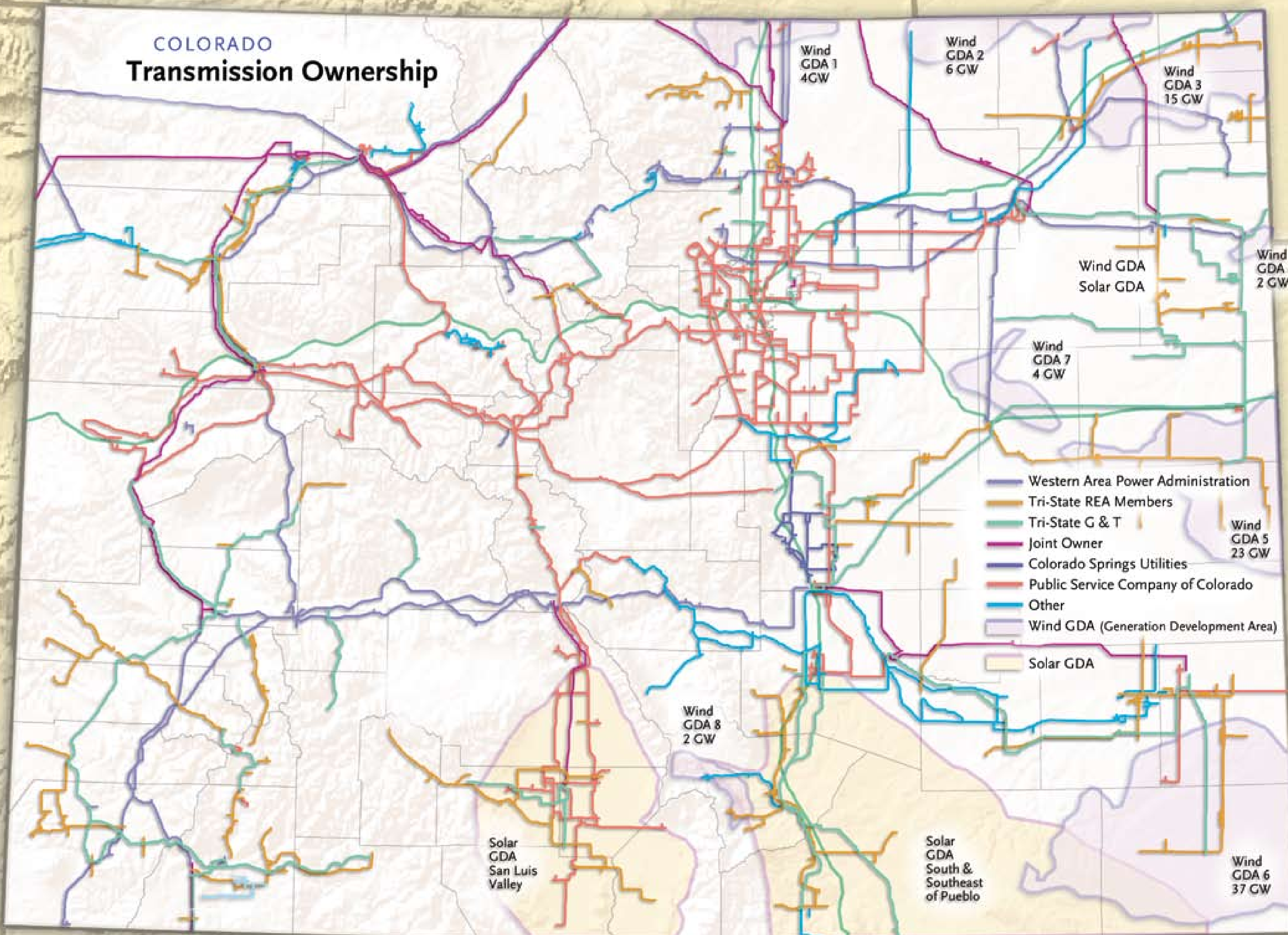
Operators keep reserves on hand for various purposes. Some reserves are held as a contingency against an unexpected line or generator outage. Other capacity reserves on quick-responding generators are ramped up or down instantly in response to changes in system frequency. Another category of service is deployed hourly or sub-hourly when actual load deviates from the previous day's forecast. Technical requirements for these various applications differ, since some require units that can change output at a moment's notice.

Wind resources vary from one moment to the next just as load does, but the variance is not the same everywhere at the same time. Greater geographic diversity across multiple wind farm sites reduces the overall variance of output. In fact, a detailed study of high wind penetration scenarios in Texas found that spreading new wind development across all the renewable energy zones in the state reduced total variance to the point that it would be manageable with existing spinning reserves.[96]

Geographic efficiencies are difficult to achieve when grid operations are not coordinated, as when regional operations are divided among several small balancing authority areas. A balancing authority area is the collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The balancing authority integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

A report produced by the Wyoming Infrastructure Authority on October 9, 2009, *Report to the Legislative Task Force on Wind Energy Transmission Sub-Committee*[97] drew similar conclusions:

"A potential operational benefit of a broader collector system could be to expand the pool of resources used to balance the system. These resource pools are called 'balancing areas' within the electrical industry. Each area is operated by a group of system dispatchers that keep the flows in and out of the system balanced at all times. It has been found



Source: Colorado Governor's Energy Office

that the expansion of these balancing areas allows more resources to be pooled, such that the impacts of intermittent resources are mitigated to an extent. Wyoming is split between two WECC certified Balancing Areas. The eastern portion of Wyoming is included within a Balancing Area operated by the Western Area Administration that includes Colorado and Nebraska. The western portion of Wyoming is included within a Balancing Area operated by PacifiCorp that includes Utah and Idaho. While each of these Balancing Areas is large on their own, both operators are looking for ways to share resources more effectively to help integrate wind resources. Elimination of the barriers between the eastern and western portions of the transmission systems within the state of Wyoming could help facilitate the statewide development of resources to supply multiple markets."

Consolidating currently fragmented operations into a single larger balancing authority area is technically feasible. In other parts of the country, a Regional Transmission Organization (RTO) or Independent System Operator (ISO) performs such functions to support a fair and transparent wholesale power market. These entities are regulated by the FERC, although several also are accountable to regional committees of state regulatory officials. Creating some form of a Rocky Mountain independent transmission entity charged to manage a larger balancing authority area would require a consensus among member states and among transmission-owning utilities in the region that have varied regulatory structures. To achieve such a consolidated system would require not only statutory changes, but also broad regional cooperation among multiple states and political jurisdictions.

What are the physical characteristics of the current wholesale electricity market in Colorado?

The topography of the transmission network geographically defines an electricity market. The balancing authority area defines the local market operationally, since this is where a single entity must balance generation with load and maintain reliability. Colorado has two balancing authority areas: one is operated by PSCo, the other by the Western Area Power Administration. Together, they constitute most of the Rocky Mountain Power Area (RMPA), which includes almost all of Colorado and parts of Wyoming. Total 2008 demand in the RMPA was estimated to be nearly 12,300 MW. In 2007, it peaked at just below 12,000 MW in late July.

Up one step toward a broader region is WestConnect, which comprises the utilities in neighboring balancing authority areas in New Mexico, Arizona and Nevada as well as RMPA. WestConnect itself has no balancing authority area function. Instead, it provides a forum for member utilities and stakeholders to study issues that could be addressed more efficiently if separate utilities areas were to coordinate their actions. Among WestConnect's current areas of focus are:

- How utility-scale wind and solar power can be integrated more effectively if managed across more than one balancing authority area;
- Experimental shared rate approaches to address the problem of rate pancaking;
- "Pooling" individual balancing authority areas' real-time differences between generation and demand to reduce the amount of spinning reserves needed; and,
- Coordinating transmission planning within the RMPA sub-region and between RMPA and the Southwestern Area Transmission Planning sub-region.

Westconnect has produced interactive maps that help stakeholders better understand transmission plans.[98]

The Western Interconnection is the regional grid system. Colorado is at the eastern end of this grid system, making the West Coast a large but generally remote market for power exported from other Western states. About half the power used in this vast area, which includes two Canadian provinces (British Columbia and Alberta) and a portion of Mexico is used in California.[99] WestConnect, by contrast, constitutes an effective, close-in export market where its Nevada and Arizona utility members are adjacent to the California load center for the WECC regional grid. Interconnection-wide planning is conducted by the WECC, and an increased breadth and depth of planning is now underway at this regional level.[100] The reliability and economic effect of large transmission projects that span several states are starting to be modeled and studied by WECC. The following maps show the geographic footprint of both WECC and of the WECC sub-regions.

What proposals now exist to significantly expand interstate transmission?

Several proposals exist for new regional transmission lines. Not all of the competing proposals are likely to be built. Right of way is one important limiting factor, since federal agencies — which control the desert lands that provide right of way access to the places that have access to the Southern California market —

Western Electricity Coordinating Council Region

Source: R.W. Beck/Ventyx Velocity Suite

Western Electricity Coordinating Council Regions

Source: Western Electricity Coordinating Council

are unlikely to grant federal permission to multiple lines to build redundant and duplicative projects.

The Wyoming Infrastructure Authority's October 2009 report, *Report to the Legislative Task Force on Wind Energy Transmission Sub-Committee*[101] listed the following interstate transmission projects proposed that include a footprint in Wyoming:

- Energy Gateway West, a single-circuit 500-KV AC line running between Wyoming and Idaho, to be in service between 2014 and 2017;
- Energy Gateway South, a single-circuit 500-KV AC line running from Wyoming to Nevada, which combined with Gateway West will carry up to 6,000 MW and represent 2,000 transmission miles. It has an in-service date of 2017 to 2019;
- High Plains Express, two single-circuit 500-KV lines or a new double-circuit 500-KV AC line with a 4,000- to 8,000-MW capacity, running 1,200 miles between Wyoming and Arizona, with on-ramps and off-ramps in Colorado and New Mexico. It has an in-service target of 2017 to 2018;
- Overland Intertie, a new 500-KV line running 560 miles between Wyoming and Idaho, to connect with the Southwest Intertie running to southern Nevada. It will be able to carry 2,000 to 3,000 MW and has an in-service target of 2014-2015;
- TransWest Express, a new 600-KV DC line running 750 miles between Wyoming and Nevada, and carrying potentially 3,000 MW of power, with an in-service target date of 2014;
- Wyoming-Colorado Intertie, a new 345-KV AC line running 180 miles between Wyoming and Colorado, which will resolve, with its 850-MW capacity, a long-standing transmission constraint known as TOT 3, by 2013; and
- Zephyr, a new 500-KV DC line with a 3,000-MW capacity, stretching 1,100 miles between Wyoming, Idaho and Nevada. It should be in-service by late 2014.

How to rationalize competing proposals into a comprehensive, regional master plan that meets transmission requirements at least cost, with the most benefits for many affected parties, states, tribes, and interests remains a challenge for the Western grid area.

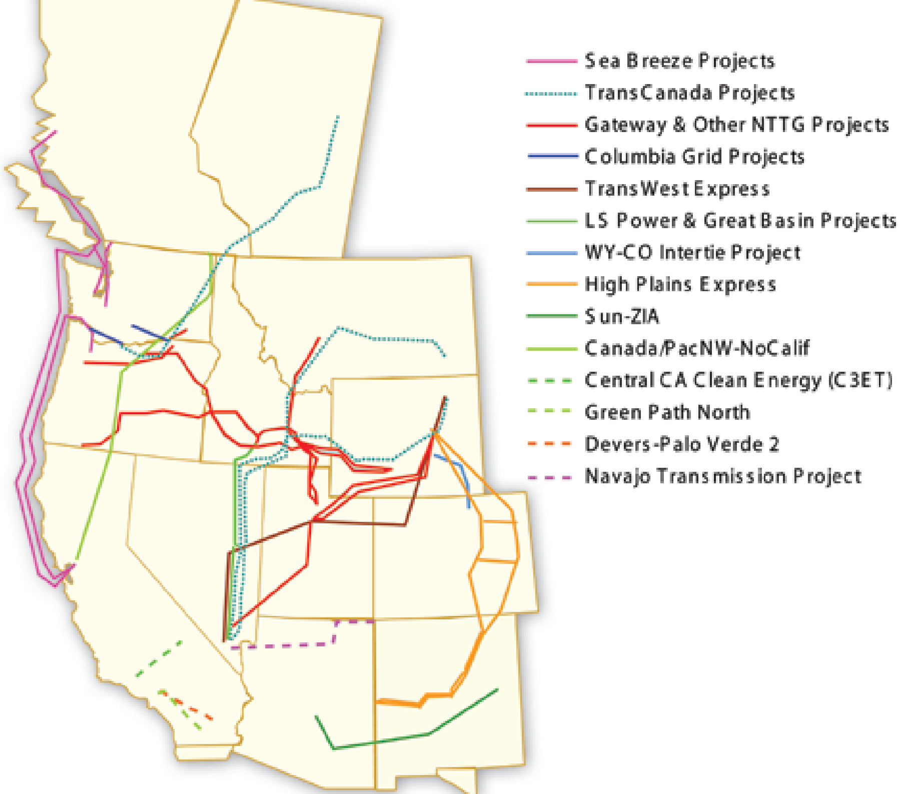
These topics have been analyzed by many entities. The Western Governors' Association's Western Interstate Energy Board has a lead role in coordinating discussion about expansion of the interstate transmission system in the West.[102] A major effort by the WECC is under way to analyze the many complexities of these topics.[103]

The Western Electric Industry Leaders (WEIL) Group also has been active in this matter.[104] This group is composed of the chief executive officers of some major electric utilities in the West.

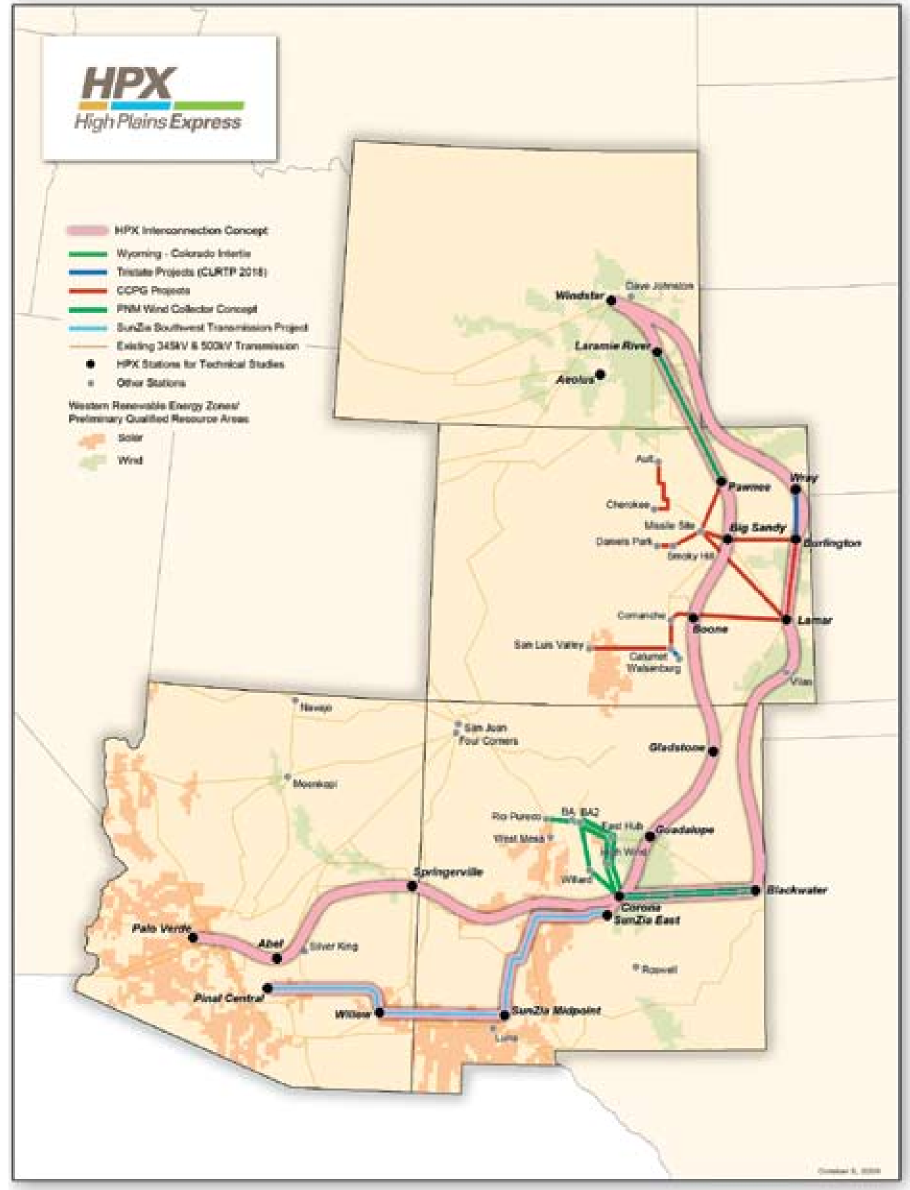
The WEIL has determined that policies favoring renewable resources can increase the cost-effectiveness of many "long lines" proposals. The group states that new multi-state lines can help high-load states meet policy goals more cost effectively and concludes that tradable renewable energy certificates produce similar value to a large new transmission line at a fraction of the cost.

A major interstate project that includes the Colorado footprint is the proposed High Plains Express (HPX)[105]. Others are the Wyoming-Colorado Intertie Project and Trans West Express.[106] The HPX, a proposed transmission superhighway is among several regional transmission plans under consideration by the HPX footprint utilities and by

Proposed Transmission Projects in the Western Interconnection



Source: Western Governors' Association

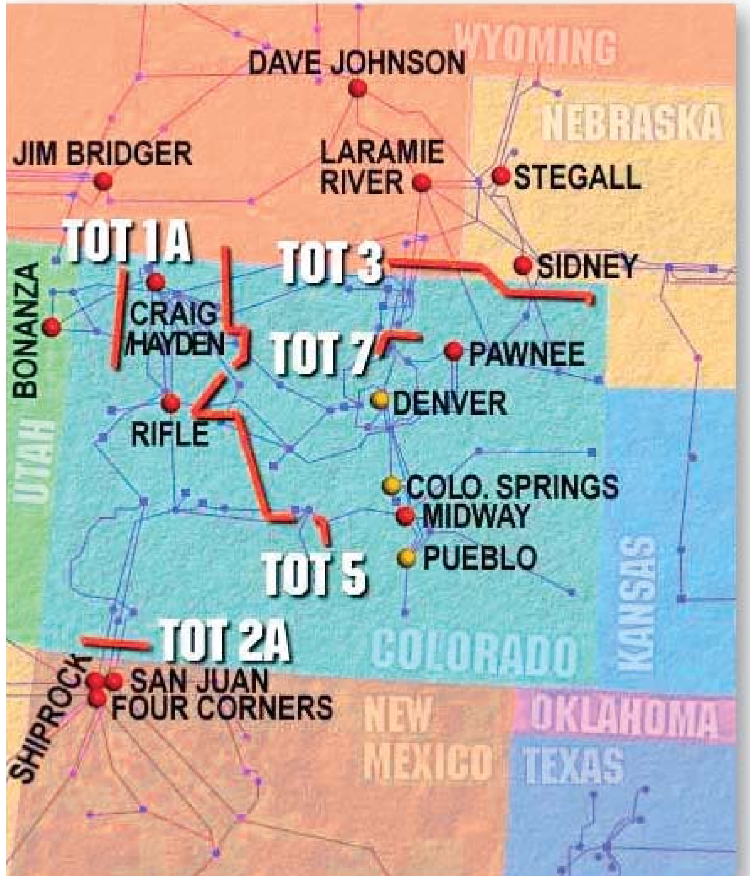


Source: High Plains Express

stakeholders in the WestConnect territory. The HPX initiative is a roadmap for transmission development in the Desert Southwest and Rocky Mountain regions to significantly strengthen the eastern portion of the Western grid. It would potentially incorporate transmission projects already being developed within the HPX area. With added North-South and East-West transmission capability, transmission for renewable energy would be provided, system reliability would be enhanced, and the economic energy transfers would provide cost-savings opportunities for electric customers in Colorado, New Mexico, Arizona, and adjoining states.

The HPX initiative is a proactive plan to expand and reinforce the transmission grid in Wyoming, Colorado, New Mexico, and Arizona. The project anticipates an alternating current (AC) system enhancement to further connect the four states and could include two 1,250-mile-long, 500 kV, AC transmission lines. Double-circuit 345 kV options also are being considered. The project is modeled as an interconnection with the existing grid at 14 substations, where power would be uploaded and downloaded. It anticipates 3,500 MW to 4,000 MW of transmission capacity. The consortium has estimated the cost at approximately $5.1 billion. The HPX model calls for a 2017 in-service operation date and anticipates the potential to integrate with four transmission projects already under study or development within the HPX area. The HPX (see above) uses an open planning process vetted with stakeholders.

Colorado Transmission Constraints



Source: Colorado Energy Forum

One key segment within the HPX conceptual footprint is the Wyoming-Colorado Intertie Project, led by LS Power (a major power development company) and Trans-Elect Development (the nation's first independent transmission company.)[107] These entities have teamed with the Wyoming Infrastructure Authority, an independent entity created by the State of Wyoming, to promote development of transmission infrastructure. The line is designed to carry 850 MW over a 180 mile stretch from east-central Wyoming to Colorado's Front Range and is expected to cost more than $200 million. Trans-Elect received capacity commitments in 2008. The project is intended to help alleviate the long-standing transmission constraints on the Colorado-Wyoming border (known as TOT 3), which has a capacity limit of 1,600 MW.

What are the limitations of Colorado's transmission system within the regional context?

Well known constraints exist at specific geographic locations in Colorado's electricity system. According to the Colorado Energy Forum's September 2006 report, *Colorado's Electricity Future*:[108]

"Colorado's transmission system is characterized by nonsynchronous operation to the east (i.e., connections to the Eastern electric grid have to be made through AC to DC to AC converters such as the Lamar DC tie because the two grids are not electrically compatible), very limited connections from the southeast into New Mexico and constrained transmission paths from Wyoming (TOT 3), Utah (TOT 1A), the Four Corners region (TOT 2A), two significant internal transmission constraints between Western Colorado and the Central Mountain region (TOT 5), and between the Fort Collins area and Denver (TOT 7)."

The graphic above illustrates "TOTs," named that because they represent the "totality" of transmission lines taken together in these constrained areas.

The ability to integrate new renewable resources into the existing Colorado system is constrained locally by physical limits on transfer capability within the RMPA transmission area. Renewable energy exports are further limited by the lack of regional transmission lines from Colorado to the primary markets in the Southwest and the West Coast.

What are the economic characteristics of Colorado's current wholesale power market?

Competitiveness is one main measure for contrasting wholesale power markets in the United States. Federal policies since the 1990s have moved the industry toward a paradigm of competition, albeit unevenly. Today some regions have organized wholesale power markets, while others — including most of the western states — still operate under state regulation, utility-by-utility. The competitiveness of the prevailing wholesale market is important to renewable energy development because it affects a state's ability to achieve its clean energy goals at the least cost to electric customers. In fact, states that have the greatest growth in renewable energy development also have organized wholesale power markets.

Colorado does not have organized wholesale markets. At the retail level, the PUC assigns utilities exclusive service territories. IOUs purchases of wholesale power are governed by a PUC-directed regulated competitive resource planning process. Wholesale providers must be successful bidders in response to RFPs issued by these utilities. Bidders that are not chosen through this process must find other markets, should they exist at all, for their power. To date, RFPs issued by PSCo have drawn power generation bidders well in excess of the levels needed by PSCo to serve its customers.

Of all the factors that limit competitive participation in the Rocky Mountain market, transmission is the most crucial. This can be remedied by materially reducing physical barriers to entry for location-constrained renewable resources, which would help to realize some of the cost-savings seen in more competitive markets.

During 2007 and 2008 PSCo and Tri-State accounted for about 65 percent of all electric generation in the state. About 16 percent of Colorado's net generation comes from city-owned generation, including Colorado Springs Utilities, the Arkansas River Power Authority, and the Platte River Power Authority (which supplies power to four northern Colorado communities, including Fort Collins Utilities, Longmont, Loveland, and Estes Park). Nearly all of the remaining 19 percent generation comes from independent power producers (IPPs) who have contracts with PSCo. Most IPP generation in Colorado is supplied by natural gas-fired units, many of them peaking units. From 2007 to 2008, however, the wind power's share of net generation in Colorado rose from less than 2 percent to more than 6 percent.

Most transactions between municipal and cooperative wholesale power suppliers and buyers involve entities that are affiliated with one another, either legally or through corporations. Aside from supplies a utility obtains from its own generation, purchases at wholesale by IOUs generally are not with affiliated companies.

In Colorado, PSCo is the dominant market, accounting for approximately 53 percent of Colorado's retail electricity sales, and for 43 percent of the state's wholesale electric generation. PSCo's retail sales (residential, commercial, industrial and other public sales such as street lighting) represent approximately 68 percent of its total generation. Another 20 percent goes to wholesale full requirements customers (such as Intermountain Rural Electric Association and Holy Cross Electric) for resale; trading accounts for about 10 percent of PSCo's generation.

The rural electric association network is a relatively closed market, constrained by "all requirements" contracts that bind the system together to ensure payment of the debt financing for its generation and transmission assets. Generation and transmission associations were formed to improve the competitive position of their relatively small members in the marketplace.

On the retail end, the state's 22 rural electric cooperatives account for approximately 24 percent of retail sales. Eighteen receive their wholesale supply from Tri-State, which accounts for 21 percent of state electric generation. Nearly all wholesale power generated or purchased by Tri-State is sold to its distribution cooperatives in Colorado, Wyoming, Nebraska, and New Mexico. The other four cooperatives, including Colorado's largest rural electric cooperative (Intermountain Rural Electric Association), are served primarily by PSCo. In most instances, these locally owned retail distribution cooperatives themselves own very little generation capacity.

The remaining retail sales — 18 percent of the state total — are supplied by Colorado's city-owned utilities. In some instances, these utilities have their own generation, or they purchase power from municipally owned joint action agencies or from other wholesale suppliers.

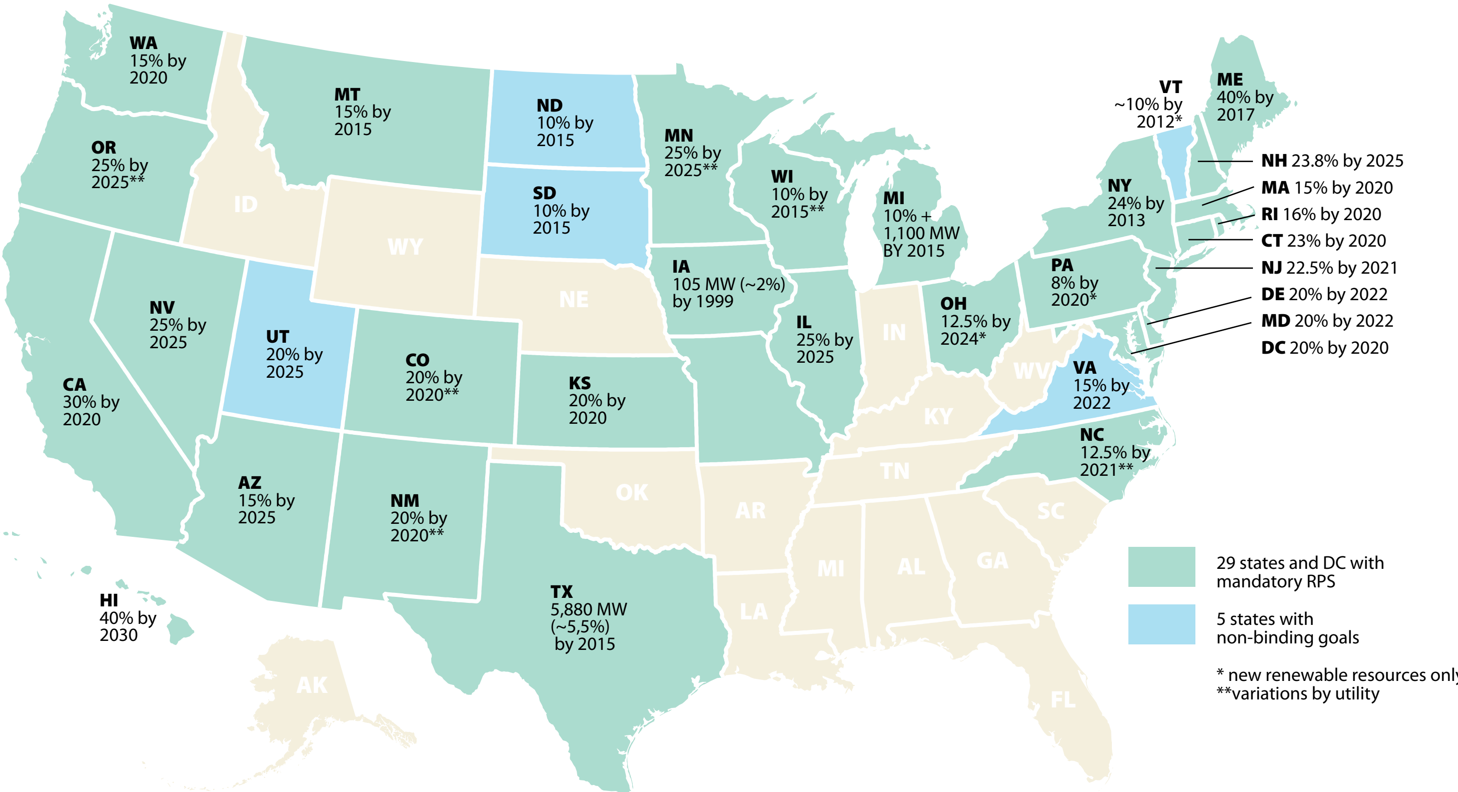
How do organized wholesale markets elsewhere in the nation approach renewable energy, transmission, and grid operations?

The nation's greatest growth in wind power has occurred in the organized wholesale markets of Texas and the upper Midwest. In these areas, wind farm developers have open access to a competitive wholesale market. Two factors make these areas attractive for wind developers.

- *Market entry is easier.* As far as the grid operator is concerned, a developer can build anywhere as long as the new plant complies with the technical requirements for interconnection, as set forth in the open access transmission tariff (OATT) under which the regional grid operates. A developer can even build a wind farm on speculation, although most prefer to have a power purchase agreement (PPA) with a utility before they move ahead with a new project.

- *Dispatch is easier, nondiscriminatory, and more transparent.* Organized wholesale markets dispatch the least-cost generating units first, based on the offer prices for each unit. Wind developers compete with each other and the rest of the wholesale power market on the basis

State Renewable Energy Standards



Source: National Renewable Energy Laboratory, DSIRE, and Lawrence Berkeley National Laboratory (September 2009)

of price every hour of the day, and they do so by offering into the market at the lowest price they can bear. In most cases, wind project enter as "price takers" — they offer at or near a price of zero, and accept whatever price clears the market for that operating interval.

The competition built into an organized wholesale market tends to keep the price of wind power low, as owners always face the risk of pricing themselves out of the market if their offer price is too high. During hours when it displaces high-cost natural gas units, wind power can lead to lower wholesale power prices overall. Wind developers face more real-time risk in an organized market, however, as there is no utility or regulator poised to say "enough" when too many competitors enter the market.

If Colorado aims to be as attractive to renewable energy developers as are organized wholesale markets, it needs to ensure that market entry is open, fair, and relatively easy. Currently, potential developers compete with each other only when a utility issues an RFP. The limitations of the transmission system at the time of the RFP can act as a *de facto* barrier to the responses. Moreover, in the case of PSCo, the amount of renewable energy it is legally able to purchase is largely a function of what was determined through the PUC-approved electric resource plan (ERP) process and the rate caps applicable to IOUs on renewable energy expenditures, established by the Colorado General Assembly.

How are other Western states meeting renewable energy goals?

All Western states except Idaho and Wyoming have RES laws in place that require specific amounts of renewable energy to be generated by certain utilities in certain years in the states. Utah has "soft targets" that utilities must meet if the renewable resources are deemed to be cost-competitive. An analysis by the Union of Concerned Scientists estimates that these existing RES requirements equal approximately 70 terawatt-hours (TWh) of new renewable energy generation by 2020, assuming current load growth rates, to which Colorado would contribute 8.1 TWh.[109] California RES requirement — 33 percent by 2020, equivalent to about 27.9 TWh of generation — is the West's largest. Wyoming does not have a RES law, although some large wind power projects there will serve customers elsewhere in the West. New Mexico's RES parallels Colorado's, with a minimum of 20 percent renewable energy requirement by 2020 for IOUs and a minimum 10 percent requirement by the same time for rural electric cooperative utilities.

To stay updated, the *Database of State Incentives for Renewables and Efficiency*[110] is widely considered the most comprehensive information on state RES laws and regulations. The map above provides an overview of RES requirements in the states.

Some Western state RES programs include restrictions or other provisions that establish a preference for in-state resources. Colorado, for example, provides a 125 percent credit for renewable energy obtained from resources sited within the state and a 150 percent credit for community-based renewable energy

The WGA, with technical support from NREL, estimated Colorado's developable export-quality renewable energy potential to be 15.7 GW of wind power, and 2.3 GW of solar power.

projects that are smaller than 30 MW capacity. Nevada counts customer-sited PV solar energy at 245 percent for RES compliance. Montana's RES rules also contain several provisions intended to promote in-state rural renewable development. Colorado, Arizona, Nevada, New Mexico and Oregon have specific goals within the RPS for distributed, solar, or other non-wind resources.

Recent NREL studies conclude that, because the pace of renewable energy expansion to date is insufficient to meet their goals, several states and regions across the country face challenges in meeting their RPS goals. For example, although California has the largest RPS requirement, indications are that the state is behind in achieving its goals. However, bidding activity in California indicates that a significant amount of additional capacity would be available beginning in 2011.[111] Nevertheless, although these studies projected shortfalls in some individual states, the Western Interconnection as a whole is on track to add total capacity sufficient to meet total RES goals. Key policy questions include how to move the most cost-effective utility-scale renewable energy from where it is located to where it is needed, and what will be the cost and benefits associated with doing so.

How are Western states identifying the best renewable energy resources?

Many in Colorado are familiar with the Colorado renewable resource assessment work conducted in the *SB07-91 Report*. Almost all the other western states have also taken steps to identify and map their renewable energy resources.

Perhaps the most comprehensive state renewable energy development infrastructure effort under way is California's Renewable Energy Transmission Initiative (RETI).[112] The RETI is a statewide initiative to help identify the transmission projects needed to accommodate renewable energy goals, support future energy policy, and facilitate transmission corridor designation and transmission and generation siting and permitting. RETI is an open and transparent collaborative process in which all interested parties are encouraged to participate. RETI assesses all competitive renewable energy zones in California and possibly also in neighboring states that can provide significant electricity to California customers by the year 2020. RETI also identifies those zones that can be developed in the most cost effective and environmentally benign manner and is preparing detailed transmission plans for those zones identified for development. The RETI effort is supervised by a coordinating committee comprised of California entities responsible for ensuring the implementation of the state's renewable energy policies and development of electric infrastructure, namely the California Public Utilities Commission, the California Energy Commission, the California Independent System Operator, and Publicly-Owned Utilities.

Arizona, Nevada, and Utah are conducting detailed assessments of their renewable energy resources with an eye toward facilitating transmission development to their areas of greatest renewable energy development potential.

With financial support from the DOE's Office of Electricity Delivery and Energy Reliability, the Western Governors' Association's project — the "Western Renewable Energy Zones" or WREZ project — has identified renewable energy zones (REZ) across the western United States and adjoining portions of Canada and Mexico. During 2008 and 2009, the WGA convened diverse groups of stakeholders to identify REZ throughout the Western Interconnection. These zones are intended to represent areas best suited for new regional transmission that would bring low-cost renewable energy to major load centers, spanning multiple states and transmission territories.

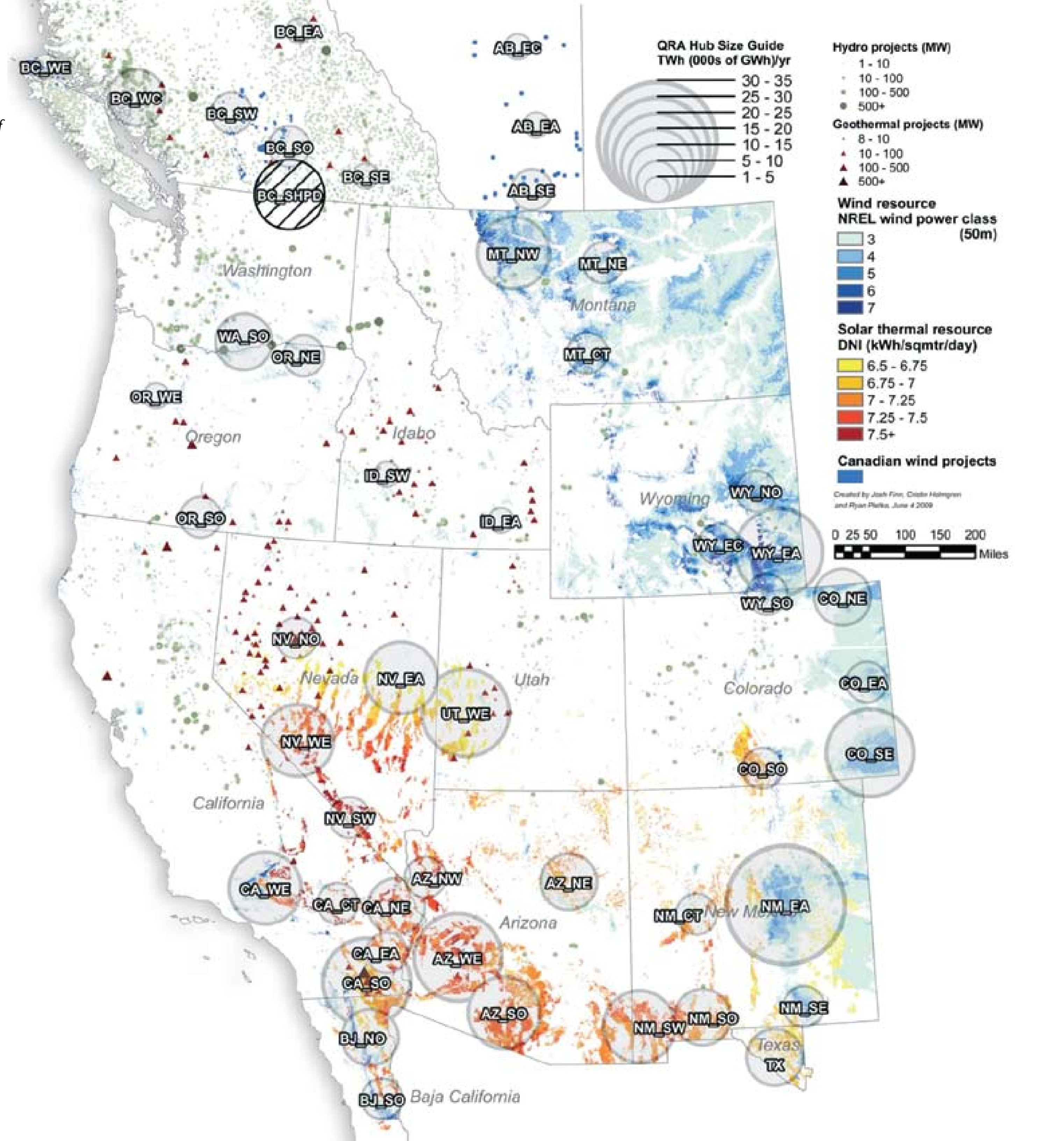
WGA found the highest concentrations of export-quality wind power to be in Wyoming and Montana. Prime areas for utility-scale solar power were deemed to be in Arizona and southern California. The greatest commercial potential for large-scale geothermal power was in northern Nevada. Studies have shown that Colorado may hold significant geothermal resources, although further exploration is necessary to fully quantify the actual geothermal potential. The zones identified in Colorado coincided with the best wind and solar GDAs identified in the *SB07-91 Report*.

WGA, with technical support from NREL, estimated Colorado's developable export-quality renewable energy potential to be 15.7 GW of wind power, and 2.3 GW of solar power.[113] Across the Western Interconnection, the report identified 94 GW of developable wind potential, 87 GW of developable solar potential, and 26 GW of commercial geothermal potential. In addition to the renewable resource potential, WGA stakeholders also compiled the best currently available data on sensitive wildlife areas in each state. The data is intended to help state policy makers and utility planners identify areas where renewable energy development would pose the least risk

Western Renewable Energy Zones Initiative Hubs

Source: Western Governors' Association

The letters "DNI" stand for Direct Normal Insolation of solar energy. "50m" denotes a hub height of 50 meters.



to wildlife habitat and other environmentally sensitive areas.

The next step in the WGA process is to develop a tool that will allow decision makers, utility planners and members of the public to compare the estimated delivered cost of renewable power from different REZs across regional transmission paths. The tool, resource maps, wildlife information, and other supporting documents are available from WGA.[114] The WGA WREZ map to the right shows these western renewable energy resources. The letters "QRA" stands for Qualified Resource Areas.

In addition to the WGA project, similar resource assessment work is under way at the NREL under the auspices of the Western Wind and Solar Integration Study.[115] The purpose of the NREL study is to support multi-state interests in understanding the operating and cost impacts due to the variability of wind solar power on the grid. This major activity intends to answer the following questions:

- How can utilities manage the incremental variability and uncertainty of wind and solar?
- Do geographically diverse wind/solar resources reduce variability and increase transmission utilization?

- How do local wind/solar resources compare to out-of-state resources in terms of load correlation or cost?
- How can hydro help with wind/solar integration?
- What is the role and value of wind forecasting?
- Can balancing area cooperation help manage the variability?
- How do wind and solar contribute to reliability and capacity value?

Colorado has more utility-scale renewable energy potential than it needs in-state. What are the opportunities to export it?

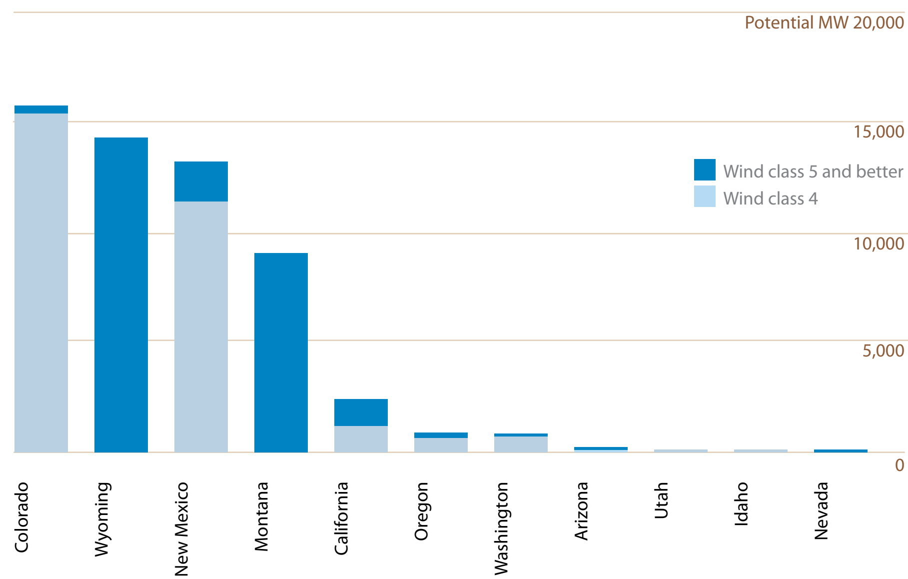
As the *SB07-91 Report* demonstrates, Colorado has more utility-scale renewable energy potential than it needs for its own domestic consumption, as is the case with most states in the WECC. This could suggest an export opportunity. There is no guarantee, however, that other states would necessarily elect to buy renewable power from Colorado. The greatest potential demand for significant amounts of renewable power is on the West Coast. However, other states may have a competitive advantage over Colorado as potential suppliers to that market due in large part to their proximity to transmission and to the West Coast.

Utility-scale solar resources in California, Arizona, and Nevada are closer to the major West Coast and Southwest loads, and the solar resources may be more productive and more consistent than wind. New Mexico's wind resources are comparable to Colorado's, and its solar thermal resources are both better and closer to the loads in the Southwest. The two graphs that follow indicate how Colorado's wind and solar potential compare to resources in other western states.

Colorado's best prospects for exporting renewable power will depend on interstate partnerships and development of a robust regional market. Combining Colorado wind with Wyoming wind or New Mexico solar power could result in a hybrid product that would follow load better than a wind resource based only on one state's resources.

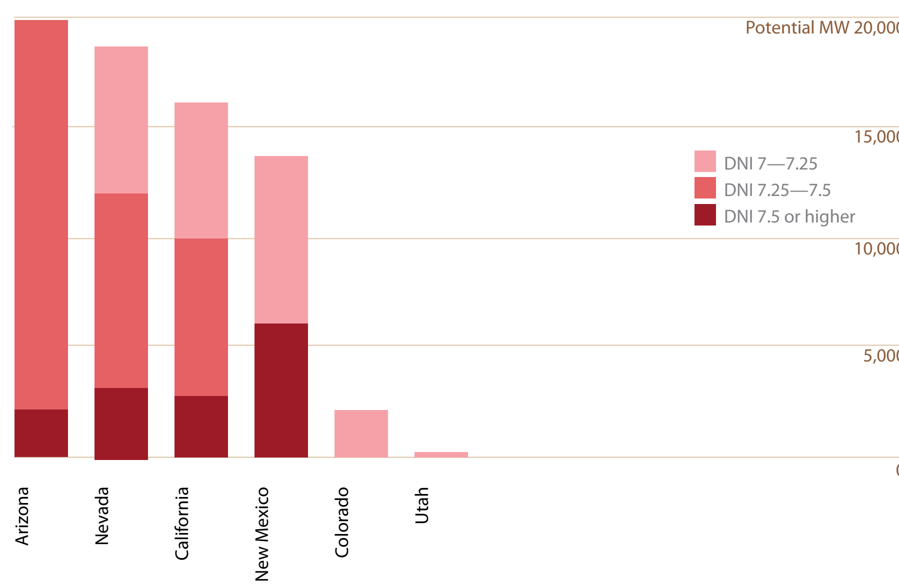
An analysis of three sample sites in Colorado and three sample sites in Wyoming conducted for this report suggests that wind power is easier and less costly to operate on the grid if sites far apart from one another are managed simultaneously on the grid. In other words, this validates the importance of geographic diversity in siting renewable energy projects. Some of the ups and downs in wind output that occur at the same moment

State Wind Potentials



Source: WGA Western Renewable Energy Zones

State Solar Potentials



Direct normal insolation (DNI) measures the amount and intensity of sunlight falling on a given ground point during a normal year. DNI is measured in kilowatts of sunlight per square meter per day.

Source: WGA Western Renewable Energy Zones will cancel each other if the sites are far enough apart.

Using this data, the 10-minute change in simultaneous output at all six sites was less than the change at any individual site for the same 10-minute interval by at least 31 percent and as much as 48 percent. This suggests that by scheduling and managing wind resources across a larger area, the variability is lower. This should result in lower grid integration costs, but it may require explicit directives from regulators to utilities.

What is transmission rate pancaking?

Each transmission owner charges for the use of its system under a tariff approved by the entity that regulates the transmission owner (in nearly all instances, the FERC). Transmission charges accrue when electricity must move through more than one transmission owner's service area to travel from where it is generated to where it is sold. In Colorado, for example, a wind developer that needs to deliver power from a project to load, could pay one transmission owner a tariffed transmission charge. Then, when that line connects to another transmission owner's line, the developer must pay an additional tariffed rate to the second transmitting company. When the second line connects to a third transmission owner's line, the developer pays a third tariffed rate —hence the term, "rate pancaking."

In contrast, organized markets with a RTO or an ISO often have single, system-wide transmission rates to facilitate system-wide delivery of power (wheeling). In doing so, they eliminate rate pancaking. These charges usually take the form of a "postage stamp rate" or a "license plate rate." A postage stamp rate is a uniform charge to pay for wheeling (or delivery) of power from within a region to any other point in that region, regardless of distance, and regardless of the number of different transmission owners along the way, and even regardless of state boundaries. It works much like a single-price postage stamp that can be used to send a letter across town or across the country. Both the rate and the disbursement of revenues are determined by formula, usually based on peak load and approved revenue requirements in each service area. Under "license plate pricing," transmission customers pay different prices based on the costs at the point at which the power is delivered to their area. They can use any part of the system after paying that fee.

At least in theory, pancaked transmission rates add to costs of delivering renewable power to markets outside Colorado. The path that electricity from an eastern Colorado wind farm would take to the West Coast might flow from the PSCo or Tri-State system and across lines owned by three or four different transmission utilities, each of which would charge a tariff. Because there is no RTO or ISO in or near Colorado, modifying transmission rates at the state level — or among states near Colorado — would require FERC approval. For practical purposes, however, the rate pancaking obstacle is trumped by a more basic obstacle: absence of a viable transmission path for renewable energy from Colorado to the West Coast. This physically limits the number of transactions for which rate pancaking might be a problem.

Nevertheless, transmission utilities that are affiliated with WestConnect have launched a regional pricing experiment intended to achieve some of the benefits of a postage stamp rate or similar regional pricing mechanism. FERC approved the pricing experiment in early 2009.[116]

What plans are there for solar energy development in Colorado's San Luis Valley?

Colorado's best solar energy resources ("highest incidence of direct normal insolation of solar energy") are in the San Luis Valley (SLV). PSCo and Tri-State have filed a joint application for a certificate of public convenience and necessity (CPCN) at the PUC to build new transmission lines and a substation in Southern Colorado, including the SLV.[117] The name of the new transmission line is the San Luis Valley-Calumet-Comanche line. The new infrastructure would bring power in and out of the SLV, connecting to the transmission backbone on the I-25 corridor. At present, the SLV is served by three lines coming from the north over Poncha Pass. If built, as currently planned, the line will go in to service in 2013. The project is intended to solve an ongoing electric reliability risk facing electric customers in the SLV and it also would provide a pathway for exporting over 1000 MW of CSP generation to be exported from the valley. The total project cost is estimated at $180 million consisting of the following segments:

- Approximately 95 miles of new double-circuit 230 kV transmission from the SLV to a new 230/345 substation to be named

Colorado already has made substantial progress to establish itself as a location for renewable energy manufacturing, most notably the $1 billion in investments planned by Vestas Wind. However, competition from other states has greatly increased.

Calumet, six north of Walsenburg.

- Approximately 45 miles of new double-circuit 345 kV transmission between the Comanche substation and the proposed Calumet substation.
- Approximately six miles of new single-circuit 230 kV transmission line between the proposed Calumet substation and Tri-State's existing Walsenburg substation.

An account of the PUC docket regarding the applications for a CPCN is available on the PUC website.[118] The San Luis Valley is being closely studied for its solar energy development potential. The map on the following page, produced for the Department of Interior, identifies four study areas for solar power development — DeTilla Gulch, Fourmile East, Los Mogotes East, and Antonito Southeast.

What are Colorado's competitive advantages with respect to renewable energy manufacturing?

Expanding manufacturing assets is critical to extracting economic value from renewable energy development in the state and broader region. In fact, some estimates suggest that as much as 70 percent of actual job generation from wind energy development occurs in the manufacturing sector.

Colorado's best long-term strategy may well be to continue to emphasize and fortify its durable strategic assets. These include its central location, its strong and evolving minimum renewable energy standard, a utility that is willing to take the lead on including renewable energy in its business plan and generation portfolio, political leadership from the Governor and the legislature, geographic proximity to resources, transportation infrastructure, favorable business environment, existing manufacturing base, and intellectual capital.

Recognizing the great strength of Colorado's existing renewable energy manufacturing base and its capability for further expansion, will allow the state to take full advantage of renewable energy development across the region. It could result in far greater economic benefits to the state than those from development of local renewable resources alone.

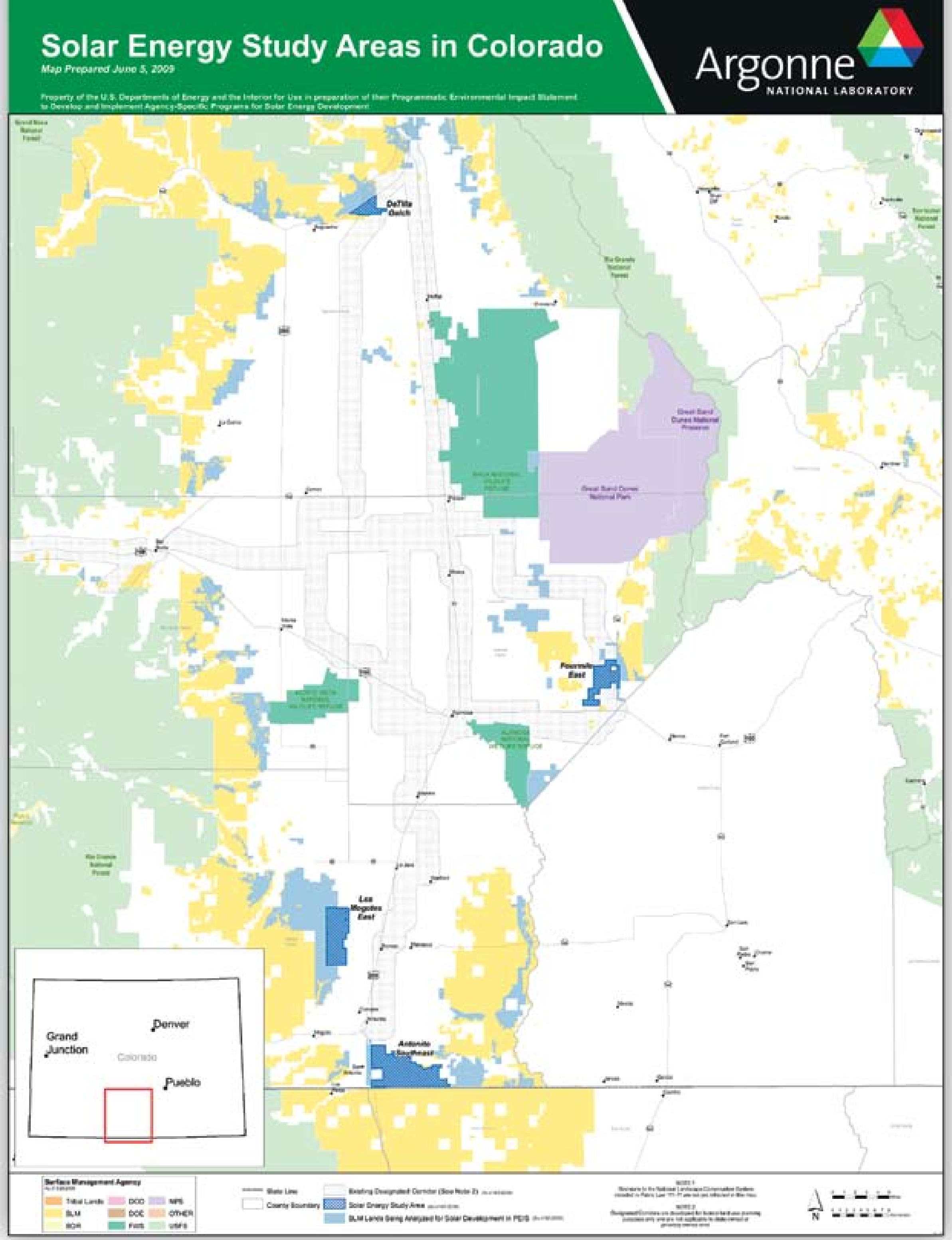
Colorado already has made substantial progress to establish itself as a location for renewable energy manufacturing, most notably the $1 billion in investments planned by Vestas Wind. However, competition from other states has greatly increased.

The National Renewable Energy Laboratory is located in Golden, Colo., and the state also is strengthened by the Colorado Renewable Energy Collaboratory,[119] a research partnership among NREL, and Colorado's premier public research universities—Colorado State University, the University of Colorado at Boulder, and the Colorado School of Mines. Colorado is also developing the Solar Technology Acceleration Center (SolarTAC), aimed at helping bring advanced, more efficient and lower-cost solar technologies to market. SolarTAC is championed by Xcel Energy, the City of Aurora, NREL, Abengoa, and SunEdison. Construction is under way, and demonstration projects are slated to begin by spring 2010.

Colorado also is pursuing diverse investment in economic fundamentals, including infrastructure and community development and workforce development, driven in part by strategic investments as a result of the ARRA. To foster continued job creation and economic development, the GEO teamed with the Environmental Defense Fund to produce *Careers for Colorado's New Energy Economy*,[86] a guidebook to help those interested in learning more about green career options. The document includes descriptions of dozens of jobs in the energy efficiency, clean energy and climate solution sectors.

According to a June 2009 report from the Pew Charitable Trusts,[87] jobs in Colorado's clean energy industry sector grew twice as fast as the state's job growth as a whole. Jobs in this sector increased by 18.2 percent between 1998 and 2007, compared to an overall job-growth rate of 8.2 percent. Pew's report documented 17,008 clean energy jobs at 1,778 companies in Colorado in 2007. Nationwide, clean energy jobs grew by 9.1 percent annually between 1998 and 2007.

Solar Energy Study Areas in Colorado



Sources: U.S. Department of Energy, U.S. Department of Interior

III. Land Use, Environment, Permitting, and Siting

Colorado's diverse topography covers more than 66 million acres (roughly 103,718 square miles). Major land cover and uses include forest lands, crop lands, pasture, and rangelands. The state has 21,637,000 acres of forest land, 11,530,000 acres of crop land, 17,342,000 acres of pasture/rangeland, and 16,191,000 acres dedicated to other uses.

Of the approximately 22 million acres of forest land, some 6 million acres are privately owned; the balance is managed by federal and state agencies. The largest federal and state land managers are the USDA Forest Service, Region 2 (14.5 million acres); the USDI Bureau of Land Management, Colorado (8.3 million acres); and the Colorado State Land Board (3 million acres).

The intersection of renewable energy and transmission infrastructure with land use issues requires thoughtful planning. Western Resource Advocates' *Smart Lines* report[120] offers that "transmission projects that facilitate renewable energy cannot receive a blank check of approval. Proper planning for siting new transmission lines is critically important to direct both renewable energy development and supporting transmission to the least environmentally sensitive areas in the West. Otherwise, new transmission can have negative effects on endangered species, habitat, and iconic western landscapes and recreation areas. This must be taken into account in the planning process." The *Smart Lines* report recommends a four-step approach to balancing the goals of reliable power and environmental protection:

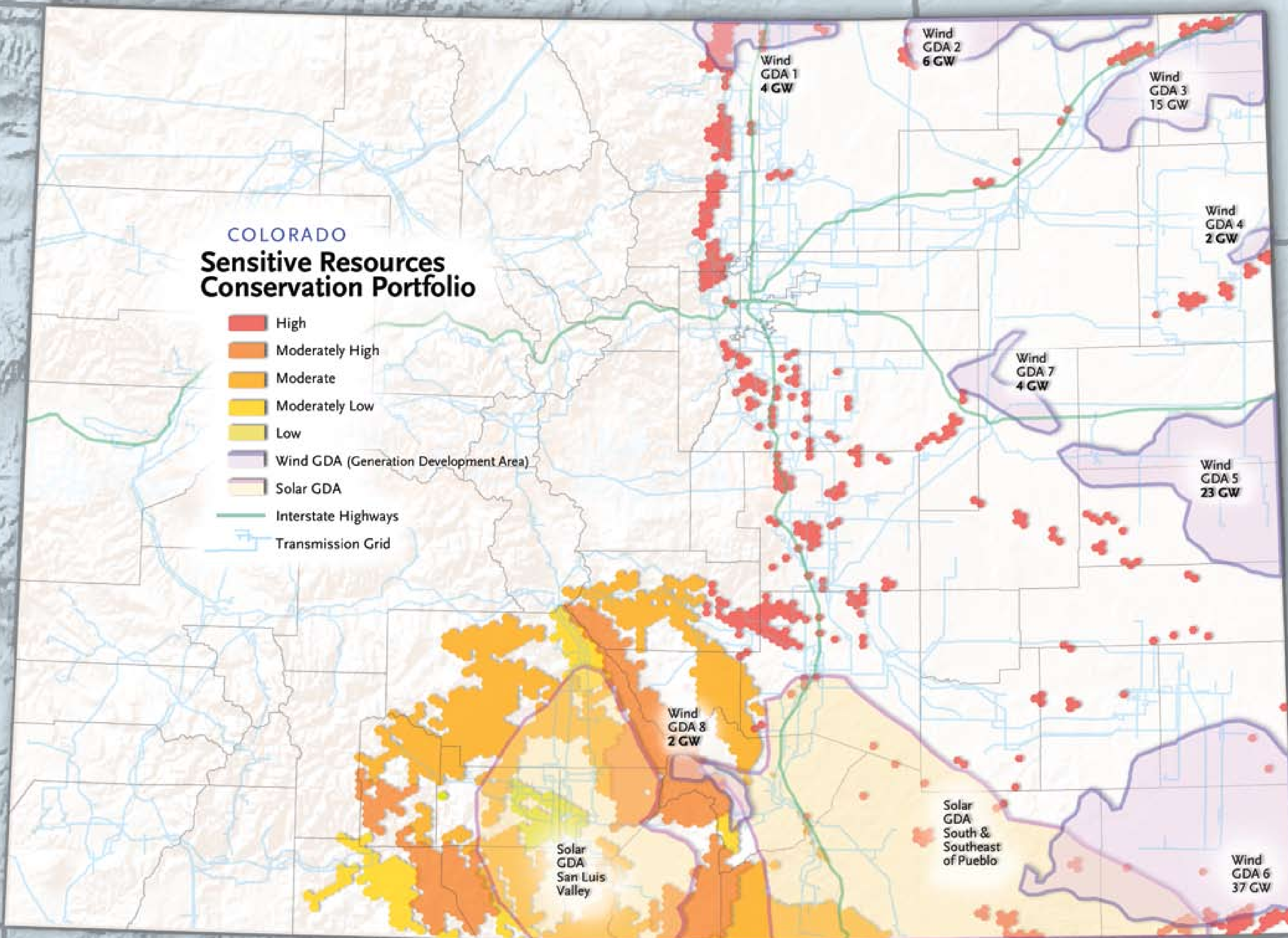
- Pursue energy efficiency first.
- Maximize use of the existing grid and existing right-of-ways by upgrading voltage capabilities and improving efficiency wherever possible.
- Connect clean and renewable energy resources.
- Ensure long-lasting protection for public lands and wildlife resources.

Colorado is home to an outstanding diversity of ecological areas that add to the attractiveness of the state as a place to live and do business. The purpose of Colorado's energy facility siting laws and regulations has been to provide a way to balance between the interests of the state and its citizens in preserving those areas and at the same time, to provide for the demonstrated need to construct both energy generation and transmission facilities to meet state requirements. Because the Colorado siting process is marked by strong local control and regulation, county permitting processes are of critical importance, although within a larger context of federal regulations and some state authority. This section first describes the ecological and other concerns in siting utility-scale renewable energy projects and transmission in Colorado and then outlines the federal, state and local siting process and considerations in acquiring rights to develop renewable energy and high-voltage transmission facilities on private lands.

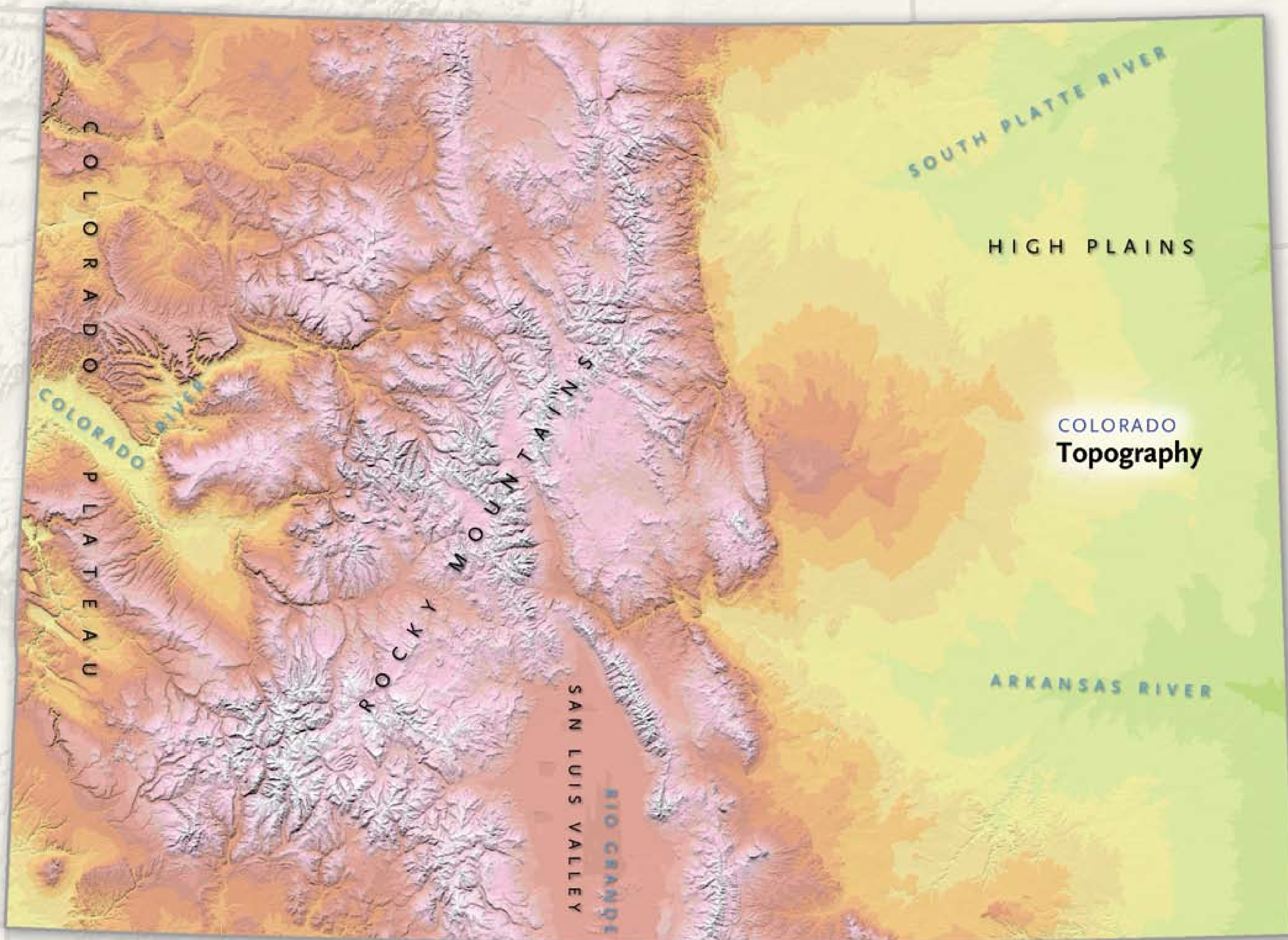
Ecological and Other Concerns

What limitations do wildlife habitat, plant species, or restricted military lands impose on the ability to build new renewable generation or transmission in Colorado?

The GDAs identified in the *SB07-91 Report* cover several large resource areas in eastern and southern Colorado, although only a small fraction of that land area would need to be developed with wind and solar plants to meet the 20x20 goal. Additional land would be developed should Colorado export its renewable power to markets in the Southwest or other parts of the country. Some areas of land are more suited to development than others. The REDI Project land use consultant — Worley-Parsons (WP), identified ecological and



Source: WorleyParsons, Colorado Governor's Energy Department


COLORADO
Topography
HIGH PLAINS
SOUTH PLATTE RIVER
ARKANSAS RIVER
ROCKY MOUNTAINS
COLORADO PLATEAU
COLORADO RIVER
SAN LUIS VALLEY
RIO GRANDE

Siting transmission lines has proven to be significantly more difficult than siting wind in recent history

cultural issues that wind farms, solar farms, and transmission line developers face as they go through the project development process.[121]

Research for this report indicates that only a few areas within Colorado's GDAs present major siting challenges that are so significant that they may actually preclude renewable energy project developments. However, siting transmission lines has proven to be significantly more difficult than siting wind in recent history. Both renewable energy generation and transmission developers take into account possible constraints that may result from the presence of endangered species (those threatened endangered or candidates for such listing, or considered to be sensitive to development) or habitats.

A significant portion of the land area the GDAs encompass is, however, in what some identify as a cautionary area — although development is not prohibited, it must be carried out carefully and, in some specific areas within the GDAs, it may require transmission line re-routing and/or modification of renewable generation facilities to accommodate the constraints in other ways.

The map on the right shows the GDAs overlaid with sensitive conservation areas. The map demonstrates that a portion of all the GDAs contain at least one conservation area. A conservation area is an area in which native species, communities and ecosystems are located or is an area that must retain its original landscape integrity — native prairie, for example. The maps produced by the REDI Project are not static, as they are subject to modifications by organizations such as the Colorado Division of Wildlife.

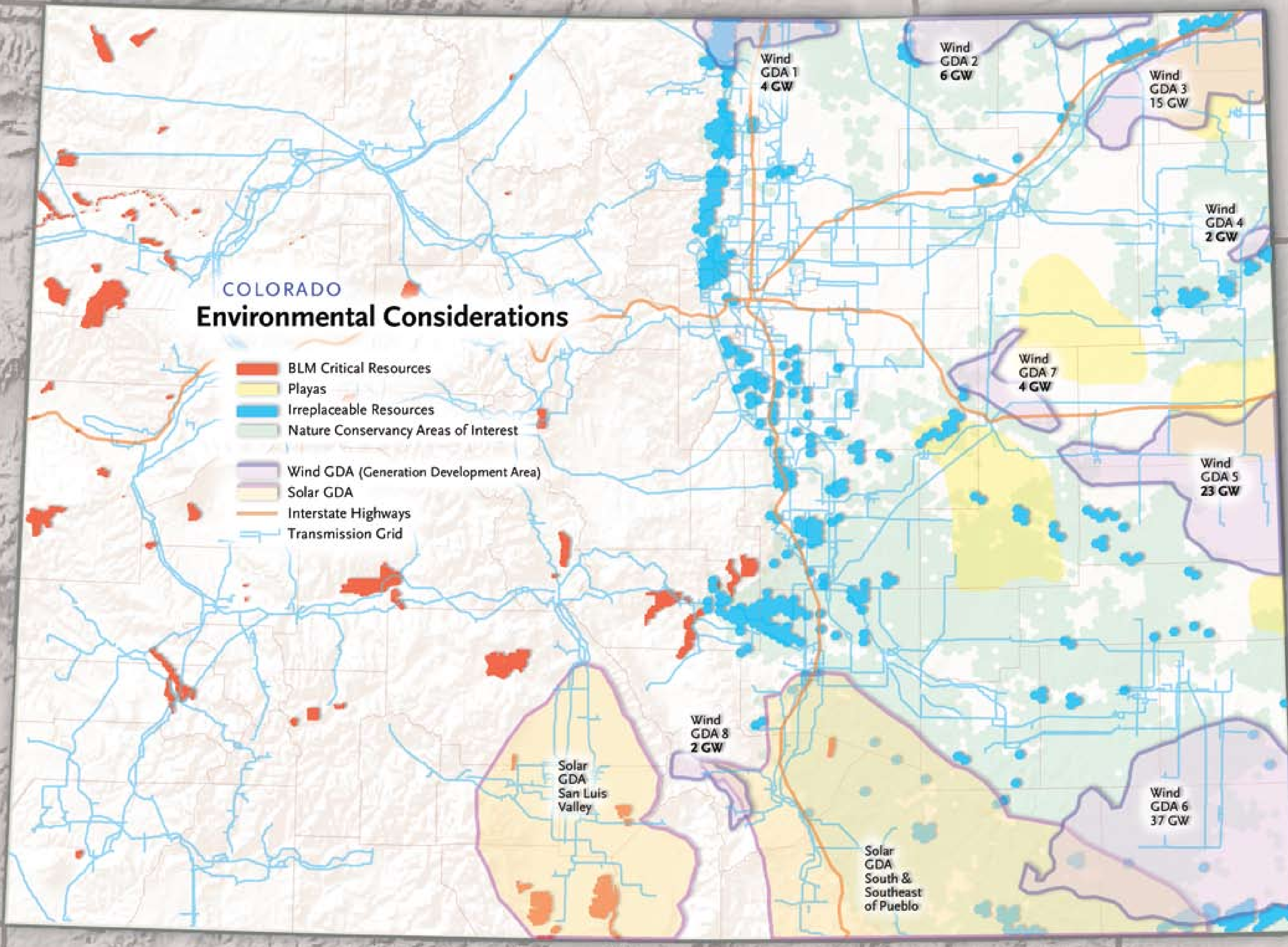
The map identifies low to very high conservation ratings and the locations of irreplaceable species. These ratings illustrate the probability of encountering sensitive or rare species and communities, and indicate the potential for high, moderate, and low constraints that developers may encounter when siting generation and transmission facilities. The map also identifies areas of environmental concerns — those locations that are likely to contain threatened, endangered, or globally imperiled species. It also identifies communities with a high avoidance designation.

Developers recognize that they must site their power plants and power lines carefully. This is particularly true in areas where there are irreplaceable species or environmentally sensitive attributes. Experienced developers understand the sensitivity of certain species to disturbance and factor such items into their siting decision. The federal National Environmental Policy Act (NEPA) requires a biological and other assessments if there is a federal nexus (oversight by a federal agency, or involving federal funding). The federal Endangered Species Act requires biological assessments if federally listed or candidate species or their habitat could be affected and the project has a federal nexus. These threatened, endangered, or rare species and communities typically are considered to be a reason to avoid building generation or transmission facilities where such effects may occur, although in many instances facilities have been permitted in such areas. The WP report suggests that developers consider examining strategies to avoid such species and their habitats in order to avoid negative impacts on the species and burdensome permitting and mitigation planning requirements.

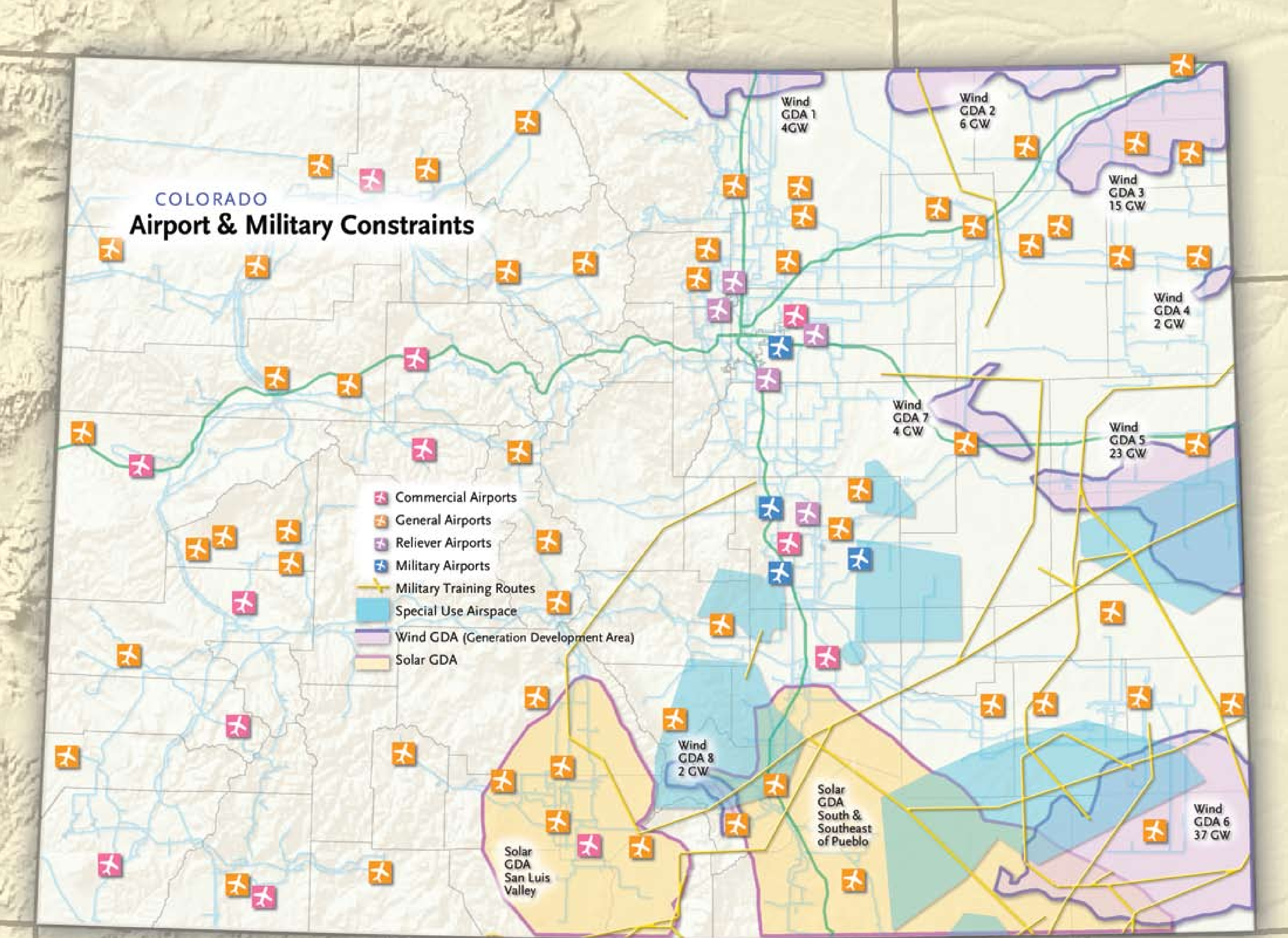
The map on the following page could be considered as an initial guide for planning. However, site-specific surveys are required to understand whether a facility is likely to affect such resources and, if so, measures to avoid or minimize such effects may be required.

Aside from wildlife-related concerns, what other concerns must developers consider when building transmission or renewable generation?

In addition to dealing with ecological constraints, developers also need to conduct overhead utility clearance studies for transmission lines that are proposed for within a few miles of existing airports and heliports. The Federal Aviation Administration would conduct aeronautical studies to determine if the proposed facilities pose a hazard to air traffic and safety. Portions of Eastern Colorado and the San Luis Valley also are used by the U.S. military for special use airspace and military training routes. These military training routes below 1,000 feet above ground level and special use areas at these locations are shown in the map on a map that follows. WP identified all the counties in the GDAs and counties that would potentially host transmission lines to deliver power from the GDAs to the Front Range markets. All counties in the areas studied by WP, except for Douglas County, and almost all the GDAs, contain special use areas or military training areas.

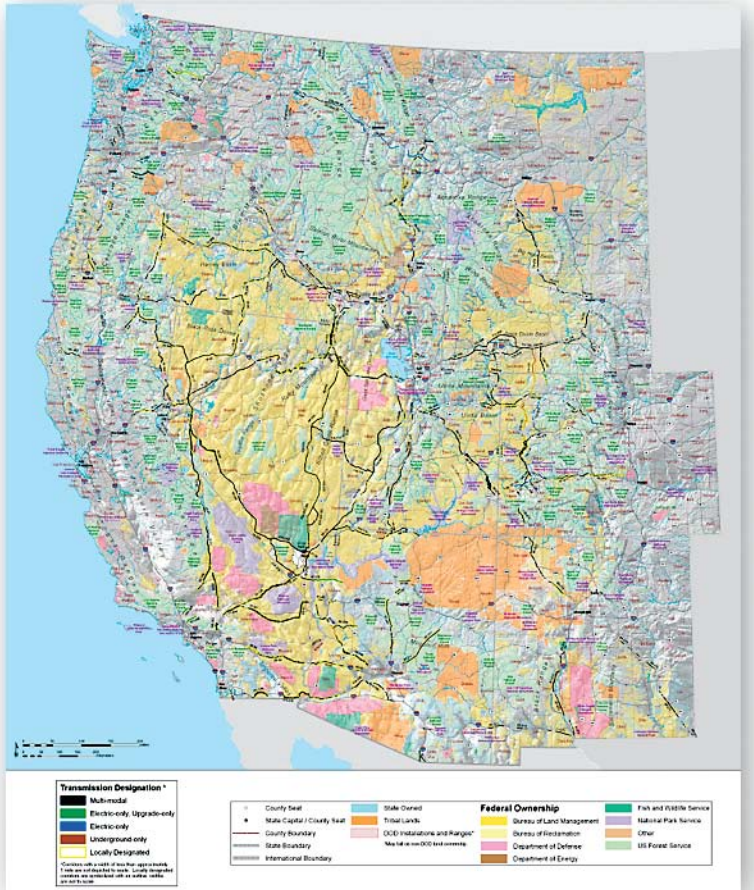


Source: Colorado Governor's Energy Office



Source: Colorado Governor's Energy Office

West-wide Energy Corridor Programmatic EIS Proposed Section 368 Energy Corridors



Source: U.S. Department of Energy, November 2008

What land use regulatory procedures must a company seeking to build new renewable energy generation or new transmission go through in order to obtain permission to build on federal, state, or county lands?

Federal Permitting

Section 368 of the Energy Policy Act of 2005 directs the secretaries of Agriculture, Commerce, Defense, Energy, and the Interior to designate under their respective authorities corridors on federal land in 11 western states (Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming) for oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities (energy corridors). The law requires these departments conduct any "environmental reviews" necessary to complete the designation of Section 368 energy corridors. These corridor designations are being litigated as a result of a recent lawsuit brought against the federal agencies by environmental groups as a result of California utilities trying to use a designated corridor. The departments conducted a detailed environmental analysis at the programmatic level. The first of the corridor maps, above, indicates the energy corridors in the West. The second corridor map, on the right, provides information specific to the corridors in Colorado.

Various federal agencies have different requirements and processes, and it is possible that a project may involve more than one federal agency and require coordination among those federal agencies. This same possibility exists at the state government level. As developers work their way "down," the project may — and frequently does — involve both county and municipal land use approvals. Substantial overlap and interaction occur between the various governmental processes, all of which create the possibility of project delays.

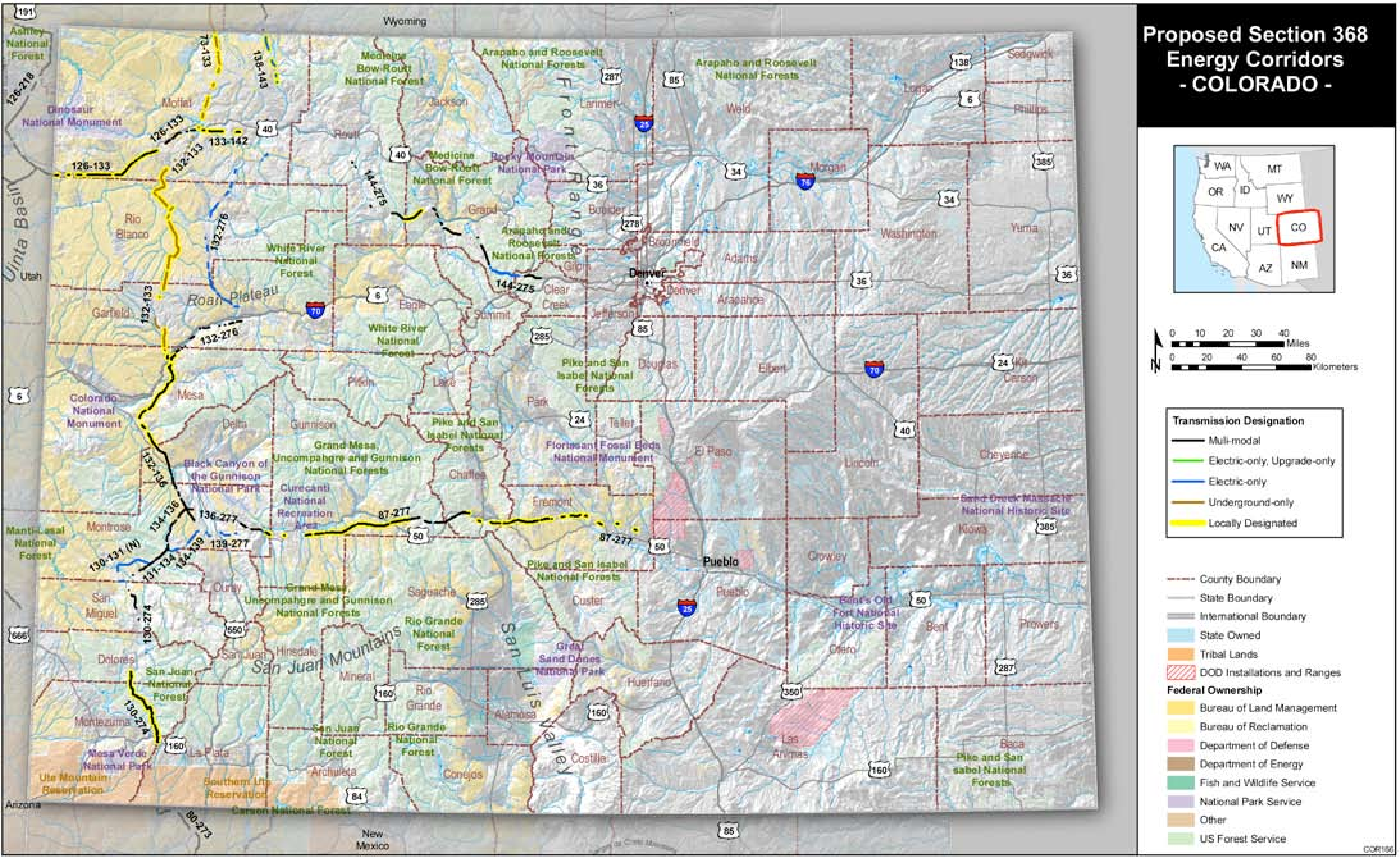
State and Local Government Permitting

The law firm of Holland and Hart's report, *Transmission Siting in the Western United States: Overview and Recommendations Prepared as Information to the Western Interstate Energy Board*[122] summarizes Colorado siting requirements:

"The siting and approval of a major transmission project in Colorado by a public utility is within the regulatory purview of the PUC.[123] Colorado courts have held that the key factor in the definition of "public utility" is whether the facility is supplying utility services "to the public," and that such a certificate is not required if the entity provides utility services only to a limited group of customers. In addition, a certificate is not required for construction, operation, or extension of a facility "in the ordinary course of business." Thus, a major transmission project that is constructed in Colorado and contains interconnections to other transmission or distribution systems which serve load in Colorado would likely need a certificate from the Colorado PUC.

Along with supplying the required technical information and design details, an applicant for a certificate of public convenience and necessity for construction or extension of transmission facilities is required to describe how it will achieve "prudent avoidance" with respect to planning, siting, construction, and operation. "Prudent avoidance" is narrowly defined to mean "striking a reasonable balance

Proposed Section 368 Energy Corridors — Colorado



Source: U.S. Department of Energy

between the potential health effects of exposure to magnetic fields and the cost and impacts of mitigation of such exposure."

An overarching factor to be considered is the public interest or need, although the scope of public interest or need is left to the discretion of the Colorado PUC.

Local Governments. The statute requiring a certificate of public convenience and necessity specifies that no public utility may construct facilities within the territorial boundaries of a city or county unless the utility complies with the applicable zoning requirements. A public utility or power authority is required to notify the affected local government of its plans to site a major electrical facility within the jurisdiction of the local government before filing a request for a certificate of public convenience and necessity or making any annual filing with the Colorado PUC that proposes or recognizes the need for new construction. Typically, a county or city will approve a transmission line through the issuance of a special or conditional use permit (a "Use Permit").

An applicant may appeal the decision of a local government denying a permit for a transmission facility or imposing unreasonable restrictions in the permit to the Colorado PUC if 1) the applicant has applied to the Colorado PUC for a certificate of public convenience and necessity, 2) such a certificate is not required, or 3) the Colorado PUC has issued an order that conflicts with the local government's action. In considering an appeal from a local decision, the Colorado PUC is required to balance the local governmental interest with the statewide interest in the construction of the facilities. In particular, the Colorado PUC is required to consider the demonstrated need for the facility, the extent that it is inconsistent with local land use plans and ordinances, whether it would "exacerbate" a natural hazard, applicable engineering standards, the merits of feasible alternatives proposed by the applicant or the local government, the basis for the local government's decision, the impact on local residents, and the safety of the public.

1041 Regulations. Colorado cities and counties are authorized to regulate by permit activities within certain areas of state interest. These permits are commonly referred to as "1041 permits" because the statute was enacted in 1974 as H.B. 1041. The 1041 process is in addition to the Use Permit process and often requires a substantial environmental analysis and consideration of project alternatives. Not all counties in Colorado have adopted 1041 regulations, but in those that have, the approval process for a project can be considerably slowed and complicated by the 1041 process. The 1041 process is applicable to "major facilities of a public utility," defined to include transmission lines and substations. However, no decision by an agency under the 1041 permit program may be inconsistent with the Colorado PUC's decision regarding public convenience and necessity."

What are the current county permitting requirements across Colorado? County permitting processes within the study area of this report vary. The study areas include both counties that have a GDA in their jurisdiction and those counties that would potentially have transmission lines delivering power from the GDAs. County processes include provisions for timing, permitting requirements, and permit fees. In general, county permitting procedures for power plants (renewable and non-renewable), transmission lines, and substations use a 1041 permit, a Use by Special Review permit, a Conditional Use permit, or a Land Use permit. The permitting requirements are fairly similar; although, the 1041 permit application typically is more comprehensive.

The following points summarize the county permitting requirements in Colorado:

1041 Permits generally are required for site selection and construction of transmission lines, power plants (renewable and non-renewable), and substations with capacities that exceed a specified threshold. The process generally includes a pre-application meeting or conference, public notice, submittal of the permit application, public hearing, approval of the permit, and post-approval requirements, if applicable. Permit applications are approved by the Board of County Commissioners. The Environmental Impact Assessments ("EIAs," see description below), which can be a major component of the 1041 permit application, are required by some counties and are encouraged in others. Counties are not federal agencies, so references to EIA in this section do not refer to federal actions subject to National Environmental Policy Act requirements. At a minimum, the Colorado Division of Wildlife (CDOW) recommends avian and bat studies as part of the EIA process for wind farm developments.

Special Review/Special Use Permits generally are required for site selection and construction of major facilities of a public utility that includes transmission lines, power plants (renewable and non-renewable), and substations with capacities that exceed a specified threshold. The process generally includes a pre-application meeting or conference, public notice, submittal of the permit application, public hearing, approval of the permit, and post-approval requirements, if applicable. Permit applications are approved by the Board of County Commissioners. EIAs (see previous discussion of EIAs) can be a major component of the Use by Special Review permit application: they are required by some counties and encouraged in others.

Conditional Special Use Permits generally are required for the site selection and construction of transmission lines, power plants (renewable and non-renewable), and substations with capacities that exceed a specified threshold. The process generally includes a pre-application meeting/ conference, public notice, submittal of the permit application, public hearing, approval of the permit, and post-approval requirements, if applicable. Permit applications are approved by the Board of County Commissioners. As discussed previously, EIAs can be a major component of the Conditional Use permit application: they are required by some counties and are encouraged in others.

Land Use Permits generally are required for siting and construction of power plants (renewable and non-renewable), transmission lines, and substations with capacities that exceed a specified threshold. The process includes a pre-application meeting, a notice to property owners, a public hearing, and approval by the County Commissioners.

Environmental Impact Assessments (EIAs) can be a major component of the permitting process; they are required by some counties and encouraged by others (EIAs are not subject to National Environmental Policy Act requirements). This generally results in a required EIA study that includes an avian and bat study of at least eight to 12 months for wind farm developments. This is typically the lengthiest and most costly component of the permit application.

WP produced several tables and charts in its REDI technical report that include further information about these processes, including estimated process duration and relative cost. The WP material is located in the REDI portion of the GEO website.[124] In most cases, the estimated process duration is controlled by the EIA or land owner negotiations. Permitting fees vary in counties in the study area, but typically do not represent a major portion of the cost; 1041 permits costs are the highest and can be as much as $25,000. Building permit fees can be a major cost for the developer. The building permit costs typically are based on the value of the project, the number of structures related to the project, or the size of the project (area and electrical generating capacity).

Do Colorado's county processes impose a burden on the overall process of siting for new transmission or renewable generation?

Generation and transmission siting processes pose distinctly different challenges. WP interviewed generation developers, utilities, and county and state officials as part of its detailed investigation. Based on this review, WP concluded that the history thus far of county-level siting processes in the Eastern Plains do not appear to impose an undue burden on the siting of new renewable energy generation.

This conclusion does not mean, however, that siting transmission is simple or straightforward. Proposals to build new renewable generation and associated transmission facilities may initially be met with receptivity, until specific corridor proposals are unveiled to build transmission lines near landowners' property or even in a specific county. When an actual permit application is filed, opposition can manifest itself in the local government permitting process. This opposition and caution can translate into delays in the permitting process, imposition of various conditions on the project, or even outright denial of the application. Conditions imposed can include a requirement to place portions of a transmission line underground or require extraordinary routing to accommodate public, political, and aesthetic concerns.

Because regional transmission projects often traverse several cities and counties, a developer must follow multiple permitting processes within each jurisdiction through which a project passes. In many other cases, however, utilities have encountered permitting delays or denials as local governments rule against permit applications. One major gap is the lack of consistency among local jurisdictions with respect to how they review and process permit applications to build new transmission. Utilities report that different cities and counties have different requirements. Some have ambiguous regulations, while others adopt regulations in response to newly proposed facilities. Some utilities in Colorado indicated that the current permitting framework is often inefficient and sometimes may add years to development schedules. Utilities report that this framework is cumbersome in cases where a linear project traverses several local jurisdictions, each with its unique processes.

Acquiring Rights on Private Lands

Aside from the governmental permitting process, what is the process for acquiring permission to use private lands for transmission?

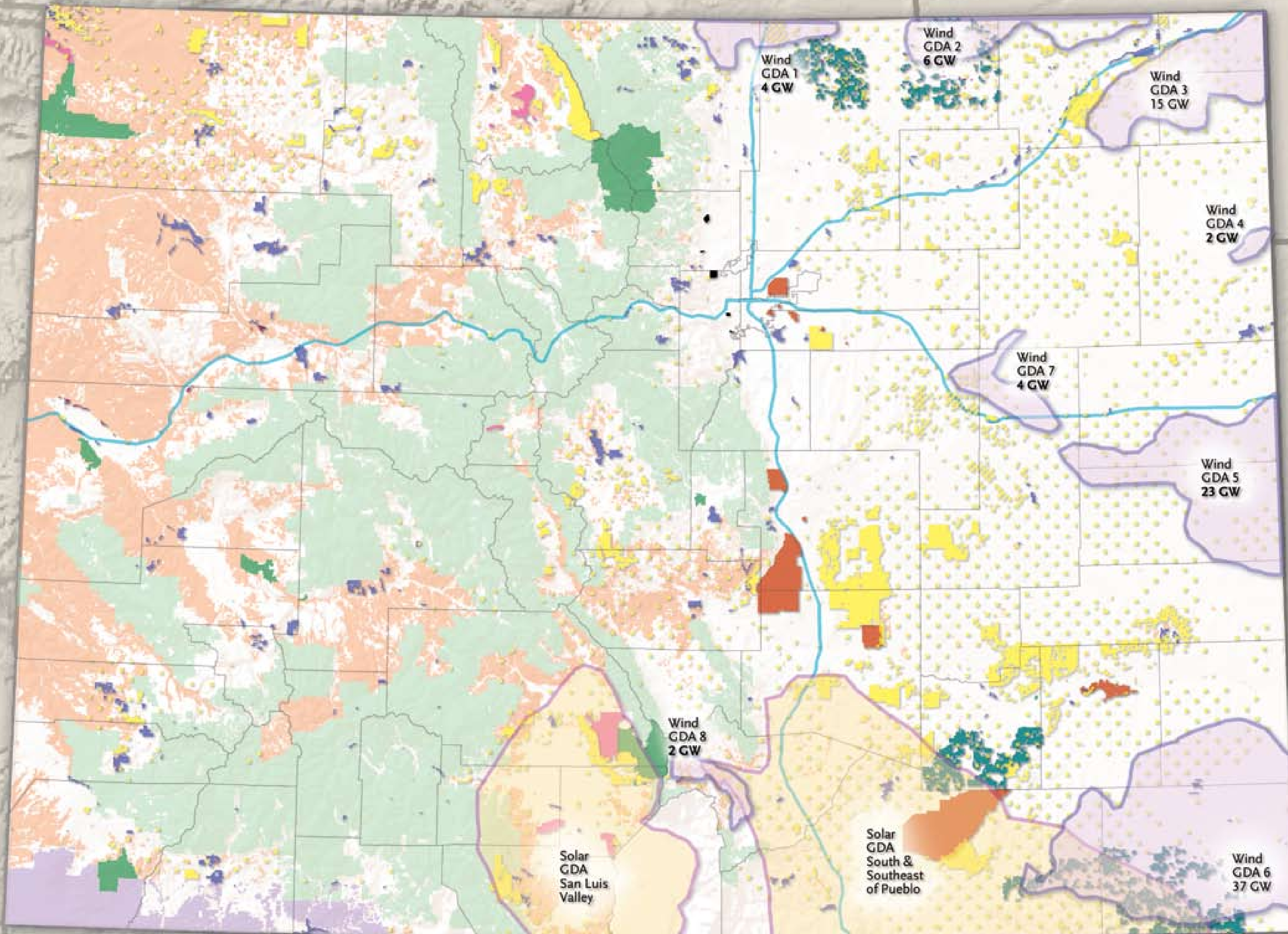
The Western Area Power Administration's guidance document, *Working with Landowners*[125], describes the process for acquiring permission to use private lands for transmission. The document details how companies building transmission facilities obtain easements and how utilities identify a transmission line corridor, including proposed sites for transmission towers and transmission tower designs. It describes how utilities work with property owners to minimize disturbances to the land, and acquire property rights at a negotiated fair market value, based on an independent appraisal, followed by a written offer. The document continues with a description of what happens if negotiations fail. It describes how easements can be acquired through eminent domain (condemnation) proceedings. It describes how federal and state laws enable public agencies to acquire, through the courts if necessary, property rights for facilities to be built in the public interest. Eminent domain proceedings are used only if an agreement cannot be reached or if title matters do not allow for a clean transfer of the necessary land rights. Through the eminent domain process, a court determines the just compensation to be paid to the property owner.

Although utility transmission developers have the legal authority to use the power of eminent domain, utilities indicate that they rarely invoke that power, relying instead on negotiated settlements with landowners. It is not clear whether private, non-utility developers that build independent transmission lines and radial connector power lines to connect a generation facility to utility transmission have the power of eminent domain. According to some attorneys practicing in this arena, such transmission companies may have the power of eminent domain. No determination on this matter is included in this report.

In some cases, it can take longer to secure landowner agreements than county permits. This is especially true for transmission line corridors. It was reported that it took a team of dedicated NextEra Energy Resources (then known as FPL Energy) staff approximately one year to negotiate the easements for a 70-mile-long transmission line for its 400 MW Peetz Table wind farm. The adjacent map shows the location of public and private lands in the state. It provides an indication of the significant amount of negotiation with private landowners that is likely to be required to build new renewable generation and transmission in Colorado.

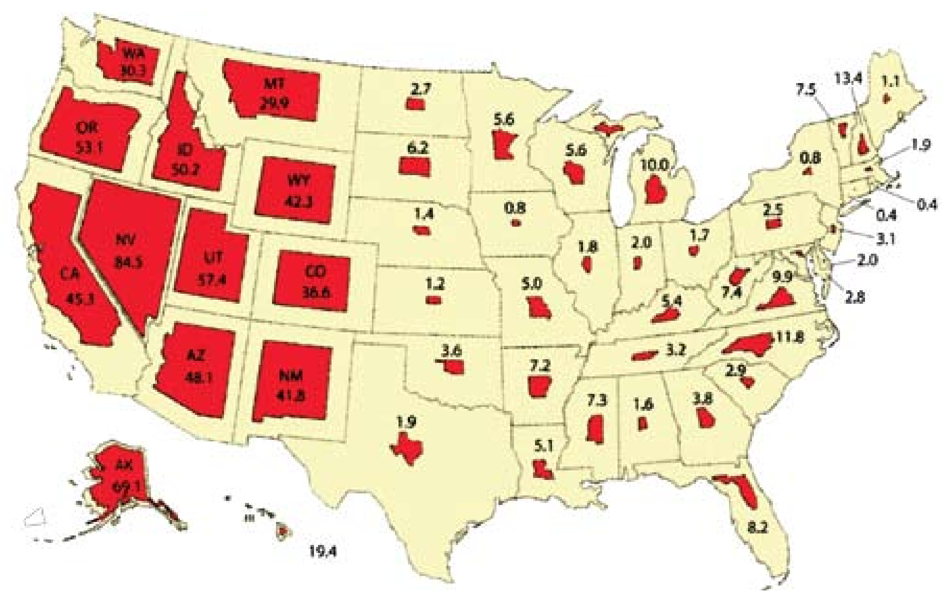
What renewable energy and transmission opportunities are there on the Colorado State Board Land Commissions' property?

HB07-1145 was signed by Governor Ritter on April 26, 2007. The legislation modified and added to statutory language governing the activities of the State Board of Land Commissions, specifically C.R.S. 36-1-147.5. The legislation encourages the Board of Land Commissioners to identify state-owned land that is suitable and appropriate for development of renewable energy resources and encourages the board to collaborate with the Governor's Energy Office and other state and federal agencies to ensure that developers are



Source: Colorado Governor's Energy Office

Federal Land as a Percentage of Total State Land Area



Source: U.S. General Services Administration, Federal Real Property Profile 2003, excludes trust properties.

aware that state land is suitable and available for renewable energy development. It also defines renewable energy resources and authorizes the board to enter into leasing arrangements at terms as determined by the board. The board's authority to issue right-of-way agreements for electric power lines granted in C.R.S. 36-1-136 was not subject to this legislation. However, the board has expressed a desire to have staff manage these agreements so that impacts to state land are minimized. The Board of Land Commissioners issues renewable energy production leases and planning leases. The board currently has five wind energy production leases in three wind farms located in Weld and Logan counties but has not issued any solar or geothermal production leases. The board currently has 13 wind energy planning leases and nine solar energy planning leases.

Planning leases generally run for two to five years at an annual rental of $3 to $5 per acre and provide the developer/lessee with the right of access to the land to do conduct feasibility studies and the exclusive right to apply for a production lease. The board has three geothermal energy lease applications on file for land in Gunnison and Chaffee counties. The board has many electrical transmission right of way agreements in place, including recent agreements covering portions of the extensive high-voltage transmission from the Cedar Creek and Peetz Table wind farms in northern Colorado. (Wind and solar planning lease forms and other renewable energy leasing information is available on the Board's website at http://trustlands.state.co.us.) The preceding map shows the location of state land that may be available for renewable energy leasing with the State Board of Land Commissioners.

The Federal Context

Any of Colorado's efforts to improve its transmission system and to integrate more renewable energy into that system will benefit from an understanding of policies that the federal government is undertaking in this area. This report's summary of the federal context is not designed to provide more than an overview of existing policies, and does not attempt to comprehensively describe the many federal jurisdictions and proposals under consideration related to greenhouse gas emissions, electricity transmission, and overall energy policy directions.

With the passage of the American Recovery and Reinvestment Act, and a strong focus on renewable energy and transmission from the federal administration, it is apparent that Colorado, and the nation, is presented with new opportunities. There is a recognition that the nation is actively attempting to keep apace with the opportunities, and federal leadership is moving to make rapid progress.

To highlight the challenge ahead, we offer the following statement by Energy Secretary Steven Chu:[126]

"The United States has fallen behind on clean energy while China and others have sped ahead. The world's largest turbine manufacturing company is headquartered in Denmark. Ninety-nine percent of the batteries that power America's hybrid cars are made in Japan. We manufactured more than 40 percent of the world's solar cells as recently as the mid 1990s; today, we produce just 7 percent. China is spending about $9 billion a month on clean energy. It is also investing $44 billion by 2012 and $88 billion by 2020 in ultra high voltage transmission lines. These lines will allow China to transmit power from huge wind and solar farms far from its cities. A report by the U.S. Energy Information Administration found that the cumulative investment in wind turbines and solar photovoltaic panels from now through 2030 could be $2.1 trillion and $1.5 trillion, respectively. The policy decisions we make today will determine the U.S. share of this market. And many additional dollars, jobs and opportunities are at stake in other clean technologies."

In addition to the many energy and environment policy changes under way, the federal context is particularly important to Colorado, given the amount of land under federal control in our state. The map to the left illustrates the overall percentage of federal land across the country.

The Department of Interior is now actively involved in discussion about renewable energy and transmission development. The department reported in June 2009 that:

"Interior Secretary Ken Salazar signed an order that sets aside some 676,000 acres of federal land — more than half in California — for study and environmental reviews. The Obama administration has placed solar energy development in the West on a fast track, with Interior Secretary Ken Salazar signing an order that sets aside more than 1,000 square miles of public land for two years of study and environmental reviews. The Interior Department is creating Renewable Energy Coordination Offices in western states to help complete reviews on the most ready-to-go solar, wind, geothermal, and biomass projects on public lands. The Department has identified twenty-four "Solar Energy Study Areas" that the Department of the Interior is evaluating for environmentally appropriate solar energy development across the West. These areas alone are estimated by the Department to be capable of generating nearly 100,000 MW of solar electricity, enough to power more than 29 million homes.

President Obama has promised to promote the use of federal land for the production of alternative energy and has set a goal of obtaining 10 percent of the nation's electricity from renewable sources by 2010. Salazar vowed to have 13 "commercial-scale" solar projects under construction by the end of 2010. Federal land managers have already announced plans to establish areas of concentrated wind and geothermal energy harvesting. The Bureau of Land Management has received about 470 renewable energy project applications. Those include 158 active solar applications, covering 1.8 million acres. The announcement opens up land in six Western states to leasing by private companies."

In a policy development that could serve as a potential template for Colorado, on October 13, 2009 California Governor Schwarzenegger and U.S. Secretary of the Interior Ken Salazar signed a memorandum of understanding (MOU) to expedite the siting of California renewable energy projects. California is the first state to sign an MOU with the Department of the Interior to cooperatively develop long-term renewable energy plans and to shepherd eligible projects through state and federal permitting processes that can receive 30 percent federal tax credits under the American Reinvestment and Recovery Act. The MOU commits the federal government to work with California on a science-based process for reviewing, approving and permitting renewable energy applications in California, which will greatly help the state reach its goal of 33 percent renewable energy by 2020. The DOI and the California Natural Resources Agency will develop detailed maps of the best areas for development and conservation, allowing for expedited project siting and habitat protection. The agreement also facilitates identification of transmission corridors by December 2010 and includes the Department of Defense (DOD) in the process because some transmission lines may need to cross DOD lands.

As a follow-up to the California and Interior Department MOU, Obama Administration officials released a MOU on October 28, 2009 signed by nine Federal Departments and Agencies to make it faster and simpler to build transmission lines on Federal lands.[127] The goal of the agreement is to speed approval of new transmission lines, reduce expense and uncertainty in the process, generate cost savings, increase accessibility to renewable energy and jumpstart job creation. The agreement is aimed at cutting approval time off the normal Federal permit process and help break down the barriers to siting new transmission lines by:

- Designating a single Federal point-of-contact for all Federal authorizations;
- Facilitating coordination and unified environmental documentation among project applicants,
- Federal Agencies, states, and tribes involved in the siting and permitting process;
- Establishing clear timelines for agency review and coordination; and
- Establishing a single consolidated environmental review and administrative record.
- Instead of applicants going to multiple agencies, a single lead agency will coordinate all permits and approvals. The new process will keep applications on track by requiring agencies to set and meet clear deadline and improve transparency by creating a single record to be posted on line. The MOU does not alter the author-

ity of any participating agencies, and all existing environmental reviews and safeguards are maintained fully.

The Federal Energy Regulatory Commission (FERC). FERC oversees and approves rates for interstate transmission and has a "backstop" role in siting certain new transmission lines. FERC Chairman Jon Wellinghoff has expressed a strong interest in the relationship between transmission and renewable energy generation, and he has often stated a desire to develop FERC policies to encourage expansion transmission to deliver renewable generation to markets.

Chairman Wellinghoff testified before Congress in favor of S. 1733, the Clean Energy Jobs and American Power Act[128] (cap and trade), as a key method to spur the development of renewable energy and high voltage transmission.[129] Wellinghoff said:

"Our nation has the capability to reduce the carbon dioxide emissions much more. For example, studies show a potential to develop hundreds of gigawatts of renewable energy resources by 2030, if we expand our infrastructure adequately. Similarly, a study issued this summer indicated that energy efficiency efforts by customers could reduce our overall energy usage by nearly 25 percent. Moreover, this study did not consider the significant potential for improved efficiency on the utility side of the meter including the transmission system infrastructure under the Commission's jurisdiction. A major reason why "low carbon" renewable resources and energy efficiency are not used more extensively is that the cost of greenhouse gas emissions is, in economic terms, an "externality." In other words, the effect of these emissions is not reflected in the price of energy in the marketplace. FERC is using its statutory authorities aggressively to eliminate barriers to renewable resources and consumer energy use management, and to encourage greater efficiency in the electricity system. As such, we are using the authority we have to implement regulations and policies to address greenhouse gas emissions. But those efforts and the efforts of other Federal and State agencies, while helpful, are not enough to efficiently stem the growing accumulation of greenhouse gases in our atmosphere. S. 1733 is the key to altering this trend. Congress should enact this legislation now."

A few general themes of FERC's efforts in transmission policy include:

- Open, coordinated, and transparent planning,
- The need for infrastructure, especially with regard to renewable energy development,
- Comparable treatment of distributed generation and energy efficiency, and
- Elimination of barriers to entry of merchant and other non traditional utility investment.

Of importance to any discussion regarding transmission, FERC issued Order 890 in 2007. This order requires utilities to file documents with FERC that describe the utilities' transmission planning processes and how those processes meet nine key planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, congestion studies, and cost allocation. Through this process, FERC is encouraging greater coordination between neighboring transmission providers and interconnected transmission systems, state authorities, and others.[130]

A May 2009 presentation by Martin Kirkwood, legal advisor to FERC Commissioner Marc Spitzer,[131] illustrated a number of key issues that FERC is now examining:

- Should planning be performed on a sub-regional, regional or interconnection-wide basis?
- Who should do the planning? Should planning be coordinated through a centralized planner?
- Integration of renewables as a planning goal: Would this lead to planners or government picking resource winners and losers rather than the market?
- How can barriers to new transmission be eliminated? What financial and business models will foster investment in transmission? Is joint ownership a viable option?

FERC currently is investigating issues related to integrating renewable energy resources as a result of state laws and a potential federal renewable electricity standard. FERC has held conferences and workshops throughout the country on integration topics and will hold similar additional meetings in the future; all are designed to inform future rulemaking proceedings.

Efforts to modernize electric grids with a stronger FERC role often encounters resistance, centering on the longstanding struggle between state and federal jurisdictions. We offer the following to illustrate this point:

On June 12, 2009, Vermont Public Service Commissioner David C. Coen testified before the U.S. States House of Representatives Committee on Energy and Commerce, Subcommittee on Energy and Environment, on behalf the National Association of Regulatory Utility

Commissioners (NARUC). His testimony was entitled *The Future of the Grid: Proposals for Reforming National Transmission Policy*:[132]

"It is the long-standing position of NARUC that Congress should not expand Federal authority over transmission siting, either through amendments to the Federal Power Act or through other Federal legislation, should Congress choose to expand FERC's current authority over the siting and construction of new interstate transmission lines, we recommend that Congress incorporate the following principles into such legislation:

- Any such additional authority granted to FERC by the legislation allow for primary siting jurisdiction by the States, and provide that FERC's "backstop" siting authority be as limited in scope as possible;
- In no event should FERC be granted any additional authority over the siting or construction of new intrastate transmission lines;
- In no event should FERC be granted any additional authority to approve or to issue a certificate for a new interstate transmission line that is not consistent with a regional transmission plan developed, in coordination with affected State commissions or other designated State siting authorities, and other regional planning groups, that covers the entire route of the proposed project;
- In no event should FERC be granted any additional authority to approve or to issue a certificate for a new interstate transmission line unless there is already in place either (1) a cost-allocation agreement among all the states through which the proposed project will pass that governs how the project will be financed and paid for; or (2) a FERC-approved cost-allocation rule or methodology that covers the entire route of the proposed project;
- In no event should any such legislation allow FERC to preempt State authority over retail ratemaking, the mitigation of local environmental impacts under State authority, the interconnection to distribution facilities, the siting of generation, or the participation by affected stakeholders in State and/or regional planning processes; and
- In no event should any such legislation preempt existing State authority to regulate bundled retail transmission services."

A provision in the 2005 Energy Policy Act authorizes the FERC to allow transmission projects deemed in the "national interest" to proceed if state regulators either fail to act on such projects within a year or reject them. However, in a 2-1 decision, a 4th U.S. Circuit Court of Appeals ruled (in February 2009) that FERC interpreted the 2005 law too broadly. The panel wrote that the law allows FERC to intervene only if a state fails to act on a proposal, not if it rejects a project. That ruling prohibited the FERC from overruling state rejections of transmission projects. In September 2009, a coalition of power companies, renewable energy companies and transmission organizations asked the Supreme Court to review the Appeals Court decision. The coalition includes the Edison Electric Institute, American Public Power Association, National Rural Electric Cooperative Association, American Wind Energy Association, Allegheny Power, Trans-Allegheny Interstate Line Co. and San Diego Gas & Electric Co.

The American Recovery and Reinvestment Act of 2009 (ARRA)

The ARRA contains several provisions that are widely anticipated to provide substantial assistance to transmission development. The relevant sections of the ARRA include electricity delivery and energy reliability, loan guarantees, the Western Area Power Administration, and investment and production tax credits.

Electricity Delivery and Energy Reliability. In Title IV, page 24 of the act: $4.5 billion is appropriated with $100 million targeted for worker training and $80 million targeted for the Office of Electricity Delivery and Energy Reliability for resource assessment of future demand, with the FERC. This funding also allows the DOE to provide technical assistance to the NERC, including modeling support to regions and the states. The funds are available for expenses necessary for electricity delivery and energy reliability activities to modernize the electric grid, to include demand responsive equipment, enhance security and reliability of the energy infrastructure, energy storage research, development, demonstration, and deployment; to facilitate recovery from disruptions to the energy supply; and for implementing programs authorized in the Energy Independence and Security Act of 2007.

Loan Guarantees. In Section 406, page 30, the act amends Title XVII of the Energy Policy Act of 2005 to permit the secretary of DOE to make loan guarantees (with a cap of $500 million) for renewable energy systems, electric power transmission systems, and leading edge biofuel projects. These rules are now promulgated, and the renewable energy

Colorado's utilities, the PUC, the GEO, and other stakeholders will be operating creatively and effectively with a newly-engaged federal establishment.

industry and transmission communities widely expect easier access to capital.

Western Area Power Administration (WAPA). In Title IV, page 26 of the act, the WAPA administrator is authorized to carry loans of $3.25 billion, with a balance of $1.75 billion (not a hard cap). The money can be used for constructing, financing, facilitating, planning, operating, maintaining, or studying construction of new or upgraded electric power transmission lines and facilities. The act requires that for a project to qualify, a minimum of one end of the line must terminate in the WAPA footprint. The first major WAPA project using ARRA funds was announced in late September 2009.[133]

Investment and Production Tax Credit. The ARRA provided a three-year extension of the Production Tax Credit (PTC) through Dec. 31, 2012. Wind project developers also can receive a 30 percent investment tax credit (ITC) in place of the production tax credit (PTC) for facilities placed in service in 2009 and 2010, and also for facilities placed in service before 2013 if construction begins before the end of 2010. The ITC then qualifies to be converted to a grant from the Department of Treasury. The treasury department must pay the grant within 60 days of an application's submission.

For Colorado, the advent of federal activities in the transmission area can provide opportunities to mold federal initiatives, to use federal money for state purposes, to enlist assistance from federal agencies and their personnel, and to mobilize the leadership of Colorado's Congressional delegation in support of the state's transmission goals. Federal activities in this area have deep historical roots and they present both immediate challenges and opportunities.

A large portion of Colorado's existing transmission was built by the Western Area Power Authority, with the purpose of bringing the benefits of federal hydro electric production from dams to certain "preference right" customers—cooperative and public utilities, federal agencies, and tribes. Federal low cost investment capital and public finance have built transmission that belongs to cooperatives and public utilities. Federal lands in Colorado have been used for siting these transmission facilities. Federal agencies and their facilities, military bases, and federal impacts on land use are involved, sometimes deeply, in how the transition to a lower carbon future will proceed.

Colorado's utilities, the PUC, the GEO, and other stakeholders are will be operating creatively and effectively with a newly-engaged federal establishment. In so doing, it is anticipated that Colorado's electricity sector will effectively utilize federal resources to achieve the state's transmission goals, and to help direct federal activities toward high priority activities that support the state's interests.

IV. Gaps and Options to Address Them

A key gap underlying any effort to integrate significant amounts of new renewable generation into the Colorado electricity system is that the existing bulk transmission system does not extend to the GDAs to allow for full delivery of power from the GDAs.

This document presents the results of a study designed to examine potential pathways for how Colorado can meet the goal of reducing CO_2 emissions from Colorado's electricity sector to a level 20 percent less than 2005 levels by 2020. A major way to achieve this is to deliver rich renewable resources from far-flung generation development areas (GDAs) to major markets within Colorado or elsewhere. We note the linkage between the *SB07-91 Report* results, that identified the renewable energy resource-rich GDAs, and Governor Ritter's Climate Action Plan.

Connecting the renewable energy potential in the state's GDAs to markets, in combination with aggressive demand-side measure activities and more natural gas-fired generation, can help lead the way to meet the 20x20 goal. Colorado baseline conditions are described early in the report. This section focuses on gaps that represent challenges as Colorado seeks to more fully deploy its vast utility-scale renewable energy potential. The gaps then are linked to a series of options that Colorado may wish to consider to address the gaps.

A key gap underlying any effort to integrate significant amounts of new renewable generation into the Colorado electricity system is that the existing bulk transmission system does not extend to the GDAs to allow for full delivery of power from the GDAs. At present, the combined PSCo and Tri-State transmission system is unable to handle more than an additional 1,500 MW of generation and, although progress is being made, existing state policies have not yet closed this gap.

One way to close this gap is to change the economic incentives for, and regulatory directives to, the major Colorado transmission-owning companies and independent transmission companies interested in building transmission in Colorado. Each option described below addresses a key aspect of such a shift. The options are provided in three groups that follow — transmission system planning and operations; transmission siting and permitting; and transmission financing.

Transmission System Planning and Operations

Many of the following ideas are being discussed in various venues, and analysis in this report corroborates their importance. The options are common to any scenario for minimizing the cost of achieving a 20x20 goal. Although it certainly is possible to reduce CO_2 emissions without these changes, findings in this report suggest they are nevertheless essential to doing so most efficiently and at the least cost. The issues are highly technical and deal with the minutia of grid management, with cost ramifications for the utilities and electric customers. We therefore suggest that more studies be conducted, potentially under the continuing catalytic leadership of the PUC. The PUC's activities that have moved the transmission topic forward were summarized in a November 1, 2009 report from the PUC to the Colorado General Assembly in response to a requirement in HB09-1345.

Option: Study the cost and benefits of a larger balancing authority area footprint than currently exists for operating the electric system in the Rocky Mountain Power Area, including alternatives for multi-state governance and oversight.

Colorado's electricity marketplace is fragmented, with different pricing for transmission across different transmission system territories. Efforts to create a single transmission management system for the entire Western Interconnection foundered repeatedly in the past decade, due to growing skepticism about the benefits and feasibility of operating a competitive wholesale market encompassing the entire region. Although it is true that organized wholesale markets need transmission operations to be as efficient, low-cost, and transparent as possible so that real-time power transactions may occur at the proper prices, the same operational efficiencies also can reduce costs in a regulated market.

Colorado's transmission owners are not yet planning and operating the system in a fully unified manner. There may be additional room for considering efficiencies that are not yet captured. As the North American Electric Reliability Corporation (NERC)[134] generally concludes, geographic diversity can reduce the cost of using more large-scale wind power and solar power, but only if all generation resources in the region are managed under a single set of protocols day-to-day, and hour-to-hour. A system that increases coordination of transmission resources can enable more efficient transmission pricing, which ultimately will benefit generators and customers. The NERC's 447-page report, *2009 Long-Term Reliability Assessment*,[135] provides a wealth of detailed information on robust plans for renewable generation, greater reliance on natural gas, and the need for reinforcing America's aging and increasingly inadequate transmission grid. In addition, NERC discusses new methods to reliably integrate renewable energy on to the grid.

Wind blows at different times in different places. The farther apart numerous wind farms are — for example, some in Colorado and some in Wyoming — the more the variations at individual sites will cancel each other. The integrated production from wind farms in the two states would require less flexible reserve capacity, thereby providing a less expensive and more dependable resource.

Area Control Error (ACE) is the instantaneous difference between a balancing authority's net actual and scheduled interchange, taking into account the effects of frequency bias and correction for metered error. In other words, ACE is the difference between what energy was scheduled and what energy was actually generated. States in the Northeast and the western Canadian provinces have established ACE diversity protocols by which the control errors of several areas are combined and managed on a net basis. PSCo already is participating in an ACE diversity interchange protocol, and it advised to explore further expansion of this option. ACE sharing is important for wind generation because it allows the utility system operator to take advantage of that geographic and wind resource diversity, thus smoothing out the average production of a geographically diverse set of wind plants and making wind, on average, a more predictable resource.

Although there may be operational advantages to a larger balancing authority area, the planning function for transmission also requires additional attention and support. The CCPG planning effort is in place, and it could serve as a solid foundation for considering many issues suggested in this report. The Southwest Area Transmission (SWAT) sub-area planning group is performing parallel work with the CCPG and has held joint meetings with the CCPG. This coordination needs additional strength and support.

A detailed examination of the gaps described in this report could more fully determine the effects and potential solutions. This examination should be conducted within the broader context of existing efforts. The scope of the examination could include the following:

- *The potential benefits and possible forms of a regional institution for multi-state decisions on siting transmission for renewable energy development.* Colorado is becoming more engaged with its neighboring states in discussions about the potential of a regional authority to coordinate transmission and renewable energy development. Colorado law empowers the PUC to engage its counterparts from other states in discussions pertaining to regional transmission issues, but it is silent on whether the PUC may make a finding of need for new transmission based on regional considerations. Potential institutional models include an interstate compact (in which member states would retain authority over decisions via the compact), a regional transmission organization under FERC jurisdiction, or a more informal multistate institution with limited decision-making power. Legislators and regulators throughout the West have begun discussions exploring these options, and Colorado has been fully engaged at all levels. We especially recommend the development of a scoping document that lays out the list of issues and functions that a regional institution could address, including but not limited to the following two items. The scoping document should provide a menu of functions that could conceivably rest with a regional entity, so that decision makers could seek consensus on which ones would remain with the states and which would be entrusted to the regional entity.[136]

If Colorado is to achieve its electricity policy goals, including the 20x20 goal, at the least cost, key stakeholders should consider developing a strategic master plan for transmission that combines all of the complicated pieces.

■ *The potential for development of a region-wide pricing mechanism for use of the transmission system.* PSCo, Tri-State, and other utilities participating in WestConnect are currently experimenting with a pilot regional pricing mechanism. Colorado's neighbors in the Southwest Power Pool to the east began in 2009 operating under a special FERC-approved tariff that will share some transmission costs regionally. Experience from both these efforts will be valuable in studying how a permanent regional pricing mechanism could reduce costs and uncertainty for far-flung renewable resources. The methodology, which would collect revenues from users of the transmission system and equitably distribute them among transmission owners, would require FERC approval. It may also involve compensating existing transmission owners so that they do not lose revenues and can continue to repay debt obligations that they may have incurred to make transmission investments. A uniform regional pricing method for conditional firm service could enable more efficient use of the transmission system and enable delivery of more power from renewable resources.

■ *The potential to share Area Control Error (ACE) across a wider geographic area, thus reducing overall costs to the transmission system.*

Option: Study the benefit, feasibility, and possible procedures for developing a long-term transmission master plan.

Traditional transmission planning could be characterized as reactive, in that it responds to future electricity demand forecasts. By contrast, a strategic master plan could be proactive, in that it could direct future development. If Colorado is to achieve its electricity policy goals, including the 20x20 goal, at the least cost, key stakeholders should consider developing a strategic master plan for transmission that combines all of the complicated pieces. The following elements should be considered:

■ *Include long-term public policy goals, such as CO_2 emission limits, and water limits.* Transmission planners in Colorado and in most other jurisdictions now plan nearly exclusively to meet forecasted load growth. They also plan to ensure that utilities continue to meet reliability standards. These two needs — load growth and reliability — are traditionally the sole transmission objectives, and existing planning aims to achieve these objectives at the least economic cost. Senate Bill 07-100 has added a new dimension — planning transmission to serve beneficial ERZs. However, transmission is a binding constraint for options to address other major policy objectives, including the need to reduce CO_2 emissions. Colorado may want to establish ways to ensure that priorities such as the 20x20 goal are unambiguously incorporated into transmission planning. For example, transmission studies may consider treating load growth, reliability, and CO_2 limits as co-equal objectives to be achieved jointly at the least cost.

■ *Cover a strategic planning horizon longer than the current 10-year studies that Colorado utilities currently perform.* As described earlier in this report, several jurisdictions within the United States perform transmission planning studies that extend beyond the current 10-year timeframe used by Colorado utilities. In Texas, these longer horizon efforts have resulted in a transmission master plan that has provided long-term clarity about which areas the state will favor for wind power development. Greater clarity and less uncertainty reduce the risk associated with long-term capital investments such as generation and transmission, and less risk usually results in better financing and lower costs over the life of the investment. Longer-term forecasts and assumptions do involve greater uncertainty. Unlike traditional planning, which is primarily predictive, the purpose of longer-term planning is more directive — in that it provides an early screening of where renewable energy development is to be encouraged.

The transmission system influences the ability of renewable and other generators to site, finance, and construct new generation. When a market opportunity arises, developers often focus on where the best transmission is, rather than where the best wind or solar resources are. Longer-term transmission planning may result in some potential development areas to be removed from consideration. If done right, however, it would facilitate longer-term expansion for those areas included in the master plan. The GDAs identified in the *SB07-91 Report* provide an objective starting point for selecting areas with the greatest probability of high-density, low-cost development of wind and solar resources.

Today's traditional 10-year planning scenarios do not fit temporally with longer-term CO_2 reduction goals that extend well beyond a ten year timeframe.

Transmission assets typically have 40-60 year lifetimes, and possibly much longer. Although uncertainties still would remain regarding future load growth, new generation technologies, environmental requirements, and other factors, reducing uncertainty with regard to the state's future goals would offset some of these other factors. We commend the work that the legislature and the PUC have taken to begin investigation of these, and other, transmission issues.

Option: Change protocols governing the use of the existing transmission system to cost-effectively integrate naturally variable resources.

Although much of this report has focused on new transmission, it would also be valuable to examine the more efficient use of the existing power system. There may be some as yet unexploited opportunities to cost-effectively increase the carrying capacity of the transmission system and to allow for more effective integration of naturally variable resources into the system. Although it would not replace the need for new transmission, the more effective use of the existing system could alter the configuration of new transmission investments and reduce their overall costs. A study should examine the following:

- *The most effective use of the existing transmission system, without major new upgrades, to provide system balancing, voltage control and similar services.* In particular, the study should examine options for changing how natural gas supplies for electric generation are reserved. It also should examine the cost-effective use of storage, including but not limited to additional pumped hydroelectric storage, compressed air energy storage, or other techniques such as hydrogen, and batteries,[137] that could provide such services.
- *The potential to make transmission capacity that currently is obligated, but is rarely used, available on a non-firm basis to wind or solar power generators.*
- *The potential for using existing demand-side management and future smart grid technologies to enable more cost-effective integration of naturally variable renewable resources into Colorado's power system.*
- *Co-scheduling uncontrollable renewable resources with flexible natural gas resources, using state-of-the-art forecasting techniques for day-ahead and hour-ahead wind and solar capability.* Research indicates that such a co-scheduled resource may be stable enough to provide a constant net output level and serve as a baseload resource. A co-scheduled service that was 50 percent natural gas, and 50 percent wind and solar, used in lieu of coal-fired generation over a 24-hour period, has the potential to reduce CO_2 emissions by 75 percent for the amount of generation that was replaced.

Transmission Siting and Permitting

A number of gaps and barriers related to siting of electricity transmission in Colorado prevail. Two separate areas of focus are suggested.

Option: Examine more effective ways to address siting issues, including an examination of the advantages and disadvantages of a state-level transmission permitting framework.

Some Colorado utilities advocate the adoption of a state-level permitting framework for transmission (and possibly generation) facilities. They point to models in other states that provide a state-level permitting framework that builds in a process for local input to decision making. Other sources suggest that the current process of local control should not be changed. At question is whether a new balance can be achieved between the public interest from a statewide perspective and local needs. It may be productive for utilities, developers and local government interests to study the possible merits of a state-level transmission permitting framework.

The Western Governors' Association signed a Memorandum of Understanding (MOU) on June 15, 2009 with three federal agencies (the Department of Interior – DOI, Department of Agriculture – DOA, and Department of Energy – DOE) designed to improve the quality of data and to better share data on these issues among states and between the states and federal agencies. The following are the key elements:

- DOI, DOE and USDA will endeavor to assist the WGA in the efforts of the Western Governors' Wildlife Council, working in coordination with their member states, to create state-based decision support systems that develop, coordinate, make consistent and integrate quality data about wildlife, corridors, and crucial habitat across landscapes.
- The Parties will seek to establish state-based decision support systems that build on existing systems and include a process for reviewing data from state wildlife agencies, state natural heritage programs, federal agencies, tribes, local governments, conservation organizations and industry to enhance data quality, reliability and availability, and a process to work toward consistency for wildlife population data, mapped data

of wildlife corridors, and crucial habitat across various political jurisdictions.

■ The Parties will endeavor to develop, use and make available the various decision support systems to inform relevant decision-makers at all levels of government, and the private sector engaged in land use decisions, and to evaluate a variety of land uses while providing healthy and productive landscapes.

■ The Parties to this MOU will coordinate their respective efforts to assist in the development of state-based decision support systems. Such efforts could also be targeted on a pilot basis at expedited development of wildlife data within particular areas and for such purposes as are subsequently determined by the Parties and/or individual states.

Within Colorado, the Colorado Renewables and Conservation Collaborative (CRCC) is an informal collaborative effort between the renewable energy industry and the conservation community to constructively address conservation concerns related to renewable energy development in Colorado. Specifically, the group works to develop tools to assist the renewable energy industry to reach its project development and transmission goals while simultaneously enabling the conservation community to meet its goals. Ultimately, the participants in the CRCC hope the collaboration will result in a high-performing renewable energy industry and the opportunity to conserve vibrant prairie and mountain ecosystems in Colorado.

Success of the CRCC effort will provide the renewable energy community with cost-effective tools, a predictable and consistent development environment, and enhancement of the industry's brand equity. For the environmental community, the benefits of the CRCC effort will include reduced impacts to important plants, animals, and habitats and an enhanced ability for the conservation community to achieve its landscape-level goals.

The CRCC was launched initially by the Interwest Energy Alliance and The Nature Conservancy in August 2008. [from http://www.interwest.org/crcc_overview.htm]

Colorado can build on wildlife and habitat work already conducted by the Colorado Division of Wildlife and Colorado's utilities to further inform a variety of constituencies, including local officials and interested citizens including landowners. This could be addressed through a combined effort among the PUC, the GEO and other interested parties.

A range of experience and knowledge is available among local officials related to permitting for renewable generation and transmission. Some local officials have a solid understanding of wind energy in particular, and of the relationship between IPPs' proposals to build power plants (and utilities' plans for associated transmission) and the need for transmission owners to consider and approve these proposals. Other local officials have less experience with these processes, and would benefit by gaining more information about them.

Additional outreach activities for local government and interested citizens could provide a useful educational foundation to:

■ Describe reasons that transmission is valuable to improve power system reliability, lower overall costs of power, and reduce CO_2.

■ Provide background information about how processes for proposing and evaluating transmission system interconnections and upgrades now function.

■ Provide examples of successful local government practices for siting transmission and renewable generation based on actual practices in selected counties.

■ To the extent that Colorado pursues these options, an outreach activity could build on the work already conducted by the state's major utilities through their siting processes, the CCPG, and other processes.

Transmission System Financing

With the exception of a few independent transmission companies, it has been electric utilities and the federal power marketing authorities, such as WAPA (the Western Area Power Administration), that have historically financed transmission. This approach is expected to continue as the primary method for future transmission financing. Planning for financing transmission expansion takes place following or in tandem with transmission planning, as proposed in these options for action.

New financing opportunities have emerged as a result of the loan guarantees referenced earlier related to the ARRA. As reported earlier, the role of WAPA has recently been greatly magnified. Financing of transmission is expected to encounter less difficulty thanks to the ARRA legislation. However, given the sluggish economy, it is no surprise that financing wind projects and transmission projects is very challenging. Expanded government incentives will help, but projects still depend on credit market participants' willingness to lend.

At present, renewable energy project development contains a mix of challenges. Despite the Obama administration's emphasis on renewable energy, the economic downturn has slowed several initiatives. On the more optimistic side, the Interior Department is intent upon breaking through regulatory logjams, and the ARRA includes cash grant programs and federal loan guarantees meant to spur investment in renewable energy projects. For example, the Treasury Department has announced $3 billion in direct payments to renewable energy projects.[138] In the release of this announcement, the Treasury Department stated:

"As part of an innovative partnership aimed at increasing economic development in urban and rural areas while setting our nation on the path to energy independence, the U.S. Department of the Treasury and the U.S. Department of Energy today announced an estimated $3 billion for the development of renewable energy projects around the country and made available the guidance businesses will need to submit a successful application. Funded through the ARRA, the program will provide direct payments in lieu of tax credits in support of an estimated 5,000 biomass, solar, wind, and other types of renewable energy production facilities."

The DOE has developed the Section 1705 Loan Guarantee Program[139] to spur greater investment in transmission. The federal government's support of renewable energy and electric transmission debt obligations under the Section 1705 Loan Guarantee Program should help build the necessary confidence for the extension of credit at a reduced cost of capital. Implementation of the Section 1705 Loan Guarantee Program is an important component of the administration's plan to help jump-start the economy built, in part, on increasing use of renewable energy resources. The DOE solicitations initiate the process of making up to $8.5 billion in loan guarantee authority available for both electric generation and transmission projects under the Section 1705 Loan Guarantee Program.

A new approach towards assisting transmission financing also has emerged in the last few years with the advent of transmission infrastructure authorities.[140] Nine states (Wyoming, New Mexico, Colorado, Utah, Kansas, South Dakota, North Dakota, Nevada, and Montana) have created these authorities. Colorado legislators indicated their interest in a state role to help finance renewable energy, energy efficiency, and transmission through the creation of the Colorado Clean Energy Development Authority (CEDA) when it passed HB07-1150.[141] Statutory language in HB07-1150 that prohibits commercial lending, however, limits CEDA's actual ability to finance projects. Because of this prohibition CEDA has been unable to fulfill its intended purpose. Legislators and key stakeholders have been working to ensure that CEDA's mandate is clarified in the 2010 legislative session.

V. Conclusions

The REDI Report was produced to provide information on how the state can take steps to lower CO_2 emission reductions in Colorado's electricity sector. Progress over the past few years have resulted in a limited success in reducing CO_2 emissions in the sector. More changes are available, particularly here in Colorado if the state focuses more intently on the opportunities to connect utility-scale renewable energy generation to a more robust high-voltage transmission infrastructure.

The report examines how Colorado's electricity sector can reduce its CO_2 emissions by 20 percent by 2020 from its 2005 levels — the 20x20 goal. Colorado faces a gap between where the state's existing suite of demand-side and renewable resource policies will lead us, and the 20x20 goal. Working together, leadership from the utilities, the legislature, the PUC, the development community, and other key stakeholders, can close the CO_2 gap. In particular, the following options should be considered:

- Greatly increase investment in demand-side resources (energy efficiency, demand-side management, demand response, and conservation).
- Greatly increase investment in renewable energy development, particularly utility-scale wind and solar generation.
- Accelerate construction of high-voltage electric power transmission to deliver renewable energy from Colorado's renewable resource generation development areas to the state's major load centers.
- Strategically use natural gas-fired power generation to provide needed new power to the grid and to integrate naturally variable renewable resources.
- Consider decreasing the utilization factor of coal-fired generation and/or consider early retirement of the oldest and least efficient of the state's coal-fired generating stations.

Meeting these challenges will require continual improvements within the electric power industry, accompanied by modifications to certain regulatory and policy structures. Colorado could also benefit from even stronger interstate coordination among those who plan new generation and transmission.

Colorado's current power system may more effectively integrate renewable energy if the balancing areas were more consolidated. The current smaller balancing area may have the effect of increasing the cost of delivering renewable power to Colorado customers. Without a single balancing authority, Colorado may experience higher costs of transmitting renewable power.

Delays associated with siting and permitting high-voltage transmission lines will hamper Colorado's renewable energy development. Further studies are encouraged to consider modifications to existing permitting processes.

The report suggests stakeholders examine:

- *The benefits, feasibility and possible procedures for developing a long-range transmission master plan.* The objectives of a master plan would include the integration of traditional electric reliability and least economic costs, with the most cost-effective options to reduce CO_2 emissions consistent with state and national policies.
- *The costs and benefits of a regional balancing authority area of which Colorado would be a part.* Colorado should strengthen its engagement with neighboring states as it relates to the governance and operation of the transmission system over a multi-state area.
- *The most effective means to secure robust participation from a diverse set of stakeholders is to ensure that Colorado's lands, wildlife, scenic, and other natural resources are adequately considered.* Colorado should also consider whether to develop additional guidance regarding the avoidance of sensitive areas.
- *Whether a process should be initiated to determine the merits of creating a statewide transmission siting authority.*

In summary, the REDI Project has identified a multitude of challenges and opportunities to achieve the Governor's Climate Action Plan goal of a 20 percent reduction in CO_2 emissions by 2020 in Colorado's electricity sector from the 2005 base year. In the spirit of the New Energy Economy, the Governor's Energy Office is focused on meeting the challenges outlined in the REDI Report. We commit to strengthen our partnerships and will redouble our efforts to achieve the 20x20 goal. We welcome the interest and expertise of colleagues across the state, the region, and the nation.

Appendix I. Summary of Modeling

University of Colorado at Denver College of Engineering

The modeling research and analysis to meet the 20x20 goal was conducted by Dr. Saeed Barhaghi, Research Professor of Engineering, at the University of Colorado Denver. The following summary was prepared by Dr. Barhaghi:

For the purpose of this research I employed the MARKAL (MARKet ALlocation) energy planning modeling platform in his modeling for the REDI Project. The UCD report is entitled *Colorado Climate Action Plan Scenario Analysis for the Colorado Power Sector*. A detailed account of this work is available on the REDI pages of the GEO website.[142]

MARKAL is a "bottom-up" data-driven energy-technology-environmental systems model. It finds a least-cost set of technologies to satisfy end-use energy service demands and user-specified constraints. It calculates resulting environmental emissions. It provides a coherent and transparent framework. Data assumptions are open and each result can be traced to its technological roots. The model has a long history (more than 20 years) of widespread use (more than 50 countries). The MARKAL model is used by the EPA, the DOE, and most European countries to assess greenhouse gas emissions. The model is PC-based and provides a framework for scenario analysis of policy options. It identifies the least-cost pattern of resource use and technology deployment over time. It quantifies the sources of emissions from the associated energy system. The model quantifies the system-wide effects of changes in resource supply, technology availability, and energy and environmental policies. Finally, the model provides a framework for exploring and evaluating alternative futures, and the role of various technology and policy options.

The research began by modeling and calibrating a base case that represented Colorado's 2005 electric generation fleet using publicly available technology and emissions data from the U.S. Department of Energy's Energy Information Administration (USDOE/EIA) and the U.S. Environmental Protection Agency's (EPA's) EGrid published data. UN scientists use 1990 as the starting point, but the United States and Japan use 2005 levels. This established the 2005 base case CO_2 emissions level stemming from Colorado power plants' electricity generation at 44.44 million metric tons (MMT). This level includes 1.42 MMT of CO_2 for power that was imported into Colorado to serve the energy needs (Colorado was a net importer of electricity in 2005). The modeling indicated that, to achieve a 20x20 goal, the model would allow an outcome that accommodated a generation mix that would not exceed a total annual CO_2 emission level of 35.55 MMT by 2020.

Relying on reported data by USDOE/EIA and Colorado electric utility industry sources, the research developed a Colorado electricity energy demand forecast based on an historical pattern of electric demand. The model employed industry information data to project future energy demand. After consulting with Colorado's largest power generation companies (Public Service Company of Colorado ("PSCo"), and Tri-State Generation and Transmission Association ("Tri-State"), I employed two energy demand forecasts: a 2 percent annual load growth consistent with a more historical average, and an energy demand forecast of 1.4 percent annual load growth, reflecting the recent economic downturn and the introduction of utility-sponsored demand-side management measures.

The model examined the two load forecasts including the following assumptions: the existing fleet of power generation, publicly announced power plant retirements, publicly announced new scheduled capacity additions, and an assumption of the likely development of

1,000 MW of concentrated solar power (CSP) in Colorado due to 1) a recent proposed extension and construction of high-voltage transmission lines to the San Luis Valley, and 2) recent RFPs for hundreds of MWs of CSP solicitation by PSCo. Following these assumptions, the model then selected any additional capacity additions to meet the load based on least cost economic criteria.

The model then created a reference case that assumes the addition of the RES and demand-side management (DSM) policies that are required by Colorado law and regulatory decisions. No other RPS or DSM policy requirements or substantial voluntary measures beyond what is currently required by state law are included in the reference case.

Our reference case incorporates the state's legislatively mandated utility-sponsored DSM policy, instituted by the PUC, for Colorado's two rate-regulated IOUs. The model quantified the CO_2 reductions expected to result from these efforts alone, without speculating whether the IOUs or the non-IOUs will exceed these mandated reductions. When the model subtract the expectations of CO_2 reductions stemming from these DSM mandates, emissions fall only slightly (from 54.41 MMT to 52.96 MMT in 2020, under the assumption of 2 percent annual load growth.

The reference case also incorporates the state's RES policy for IOUs and non-IOUs. Colorado's RES requires that the two IOUs meet a minimum of 20 percent of their retail electric sales from renewable energy sources by 2020. The same RES law requires that non-IOUs meet a minimum of 10 percent of their retail electric sales from renewable energy sources by 2020. When the model adds the CO_2 reductions attributable to the RES in addition to the CO_2 reductions attributable to the DSM requirements, CO_2 emissions drop from the 52.96 MMT in the base case that incorporated DSM to 49.38 MMT incorporating RES. This becomes the reference case for the scenario analyses.

Using our reference case and no longer referring back to the base case, the model ran sensitivity cases to gauge the uncertainties inherent in load forecast and fuel prices. First the model ran a load forecast sensitivity of a 1.4 percent load growth as opposed to the reference scenario's 2.0 percent load growth. Under the 2.0 percent load growth, CO_2 emissions will rise from the 2005 emissions level of 44.44 MMT to 49.38 MMT in 2020. At the 1.4 percent load growth sensitivity case, emissions rose to 46.86 MMT. As would be expected, lower load growth results in the need for less supply-side generation resources, and this may lessen the need for transmission to serve new generation. This comports well with the oft-stated sentiment that proactive DSM policies should be expected to yield strong net total system economic benefits.

Next, we determined the gap in 2020 CO_2 levels between the reference case and our 20x20 goal. I calculate that gap to be 13.83 MMT. Put another way, I calculate that CO_2 emission levels in 2020 will need to be reduced by 28 percent beyond the levels that are on a path to be achieved stemming from existing DSM and RES requirements.

We then conducted a model run that selected a mix of fossil and renewable generating resources based on the principle of minimizing the discounted total system cost for Colorado's statewide electricity sector, subject to the parameters of the reference case.

This run incorporated two important assumptions.

The first assumption is that new conventional coal-fired generating stations will not be on the candidate list. This was done for two reasons. Placing conventional coal-fired generation on the candidate list would only result in higher CO_2 levels, defeating the 20x20 goal. The second reason is that utilities will likely not select coal-fired generation absent carbon capture and sequestration technology in place considering the regulatory and accompanying financial risks that a coal-fired generation proposal would encounter.

The second assumption is that 1000 MW of concentrated solar power (CSP) will likely be developed by 2020 due to reasons stated above and the following reasons. The first reason is that PSCo has already put out a bid for a minimum of 200 MW of CSP with storage to come on line before 2015. In January 2009, PSCo issued a request for proposal (RFP) that asked for up to 600 MW of solar power with either storage capacity or natural gas backup. In response to the RFP, PSCo received 36 solar bids. The second reason is that PSCo and Tri-State have applied for a Certificate of Public Convenience and Necessity at the PUC to build a double-circuit 230 kV transmission line into the San Luis Valley that will have the capability of delivering over 1,000 MW of CSP to the grid. A decision on the CPCN application is expected by April 2010.

The model selected the least expensive mix of power plants that would meet the 20x20 goal. The model concluded that Colorado will add an additional 3,980 MW of additional wind generation and 100 MW of additional central photovoltaics, in addition to the existing RES requirements, to meet a 20x20 goal.

The model also shows that higher levels of DSM by both IOUs and non-IOUs would be very economically advantageous, if implemented. A strong deployment of DSM would reduce the need for utility-scale renewable generation, conventional generation, and transmission.

The model found that the total system cost for the reference scenario is less than the basecase when the addition of DSM and selection of the additional wind and solar resources to meet the RES will result in less overall cost, which could be interpreted as lower rates and more savings to electric customers. This is due to the fact, that on a total system cost basis, for a 30-year planning horizon, using a net present value analysis, DSM investment costs and the higher capital costs associated with renewable energy resources is more than compensated by the avoidance gas-fired generation of any fuel costs thereof throughout the 30-year planning horizon.

Modeled Power Generation Technology##	Capital Cost# ($/kW)	Life	Heat Rate# (Btu/kWh)	AF (%)	VAROM ($/MWh)	FXDOM ($/kW/yr)	Emission Rates#		
							CO2 (lb/MWh) Output	NOx (lb/MWh) Output	SO2 (lb/MWh) Output
New Biomass CC	1,634	30	10,283	80	2.99	45.04	-	-	-
New PC with 50% CCS*	3,769	40	11,343	93	10.58	46.21	1,167	0.3730	0.6191
Com3 - Xcel Energy*	2,020	40	8,672	88	3.06	15.64	2,159	0.0000	0.0000
IGCC - Xcel Energy*	4,008	40	10,202	88	3.05	17.14	1,048	0.4270	0.7048
Bit Coal Steam	N/A	40	10,618	83	2.78	15.64	2,159	3.8953	2.3873
Sub Bit Coal Steam	N/A	40	10,474	83	2.78	15.64	2,143	3.1810	3.7048
DSF Steam	N/A	35	12,916	85	0.52	0.86	2,000	2.4683	0.1952
Diesel IC	N/A	35	12,916	85	8.89	0.86	2,000	2.4683	0.1952
New Geothermal*	3,641	30	10,283	90	22.88	16.71	N/A	N/A	N/A
Hydro	N/A	45	10,283	27	4.48	14.20	N/A	N/A	N/A
Hydro PS	N/A	45	3,754	83	2.65	16.71	N/A	N/A	N/A
New Coal IGCC with 50% CCS*	4,008	40	10,202	87	3.05	17.14	1,048	0.4286	0.7064
New Adv CT	520	30	8,553	92	2.83	8.89	921	0.0873	N/A
New Adv CC*	827	30	7,281	93	3.09	9.42	865	0.0714	N/A
CC	N/A	30	7,399	94	0.49	15.75	881	0.1532	N/A
New CC*	885	30	7,463	95	2.81	13.19	889	0.3413	N/A
CT	N/A	30	10,525	94	0.10	6.51	1,278	0.5683	N/A
New CT*	659	30	10,459	98	7.95	4.31	1,246	0.5175	N/A
New Gas IGCC with 90% CCS	1,124	30	7,952	98	2.93	19.95	86	0.0794	N/A
Gas Steam	N/A	30	13,390	92	0.52	0.86	1,587	2.4151	N/A
New Adv Nuclear**	5,500	40	10,512	92	0.60	58.00	N/A	N/A	N/A
PV_Central	3,830	30	10,283	N/A	N/A	8.96	N/A	N/A	N/A
PV_On-Site	7,519	30	10,283	N/A	N/A	8.96	N/A	N/A	N/A
Solar_CSP***	3,500	30	10,283	N/A	N/A	43.55	N/A	N/A	N/A
Wind (Include PTC)*	1,690	20	10,283	N/A	N/A	23.24	N/A	N/A	N/A
Coal Based Imports#	-	-	-	-	-	-	2,159	-	-
Gas Based Imports#	-	-	-	-	-	-	881	-	-

Notes:

CC = Combined Cycle

CT = Combustion Turbine

PC = Pulverized Coal

IGCC = Integrated Gasification Combined Cycle

Com3 = Pulverized coal unit by Xcel Energy with no SO2 and NOx impact (net of other 2 units)

PS = Pumped Storage Hydro Facility

AF = Availability Factor

Heat Rate# = Renewables' heat rates are an equivalent proxy heat rate

Capital Cost# = Updated capital costs include transmission interconnection and delivery costs. For Solar, first year cost is shown, subsequent years costs are lower.

Emission Rates# = Source of existing power plants emissions is EPA-ETS (Emission Tracking System)

Imports# = imports are transmission constrained at 5,100 GWh per year

##Sources data from DOE/EIA or EPA-NM or as noted by * from other sources

*Xcel Energy = Operates as Public Service Company of Colorado filed its 2007 Resource Plan with Colorado PUC on Nov. 2007

**GEO from FERC document

***GEO from NREL

VAROM = Variable O&M, FXDOM = Fixed O&M

The model also conducted a sensitivity run that reduced the availability factor from coal-fired power plants by 20 percent, as one method to reduce CO_2 emissions. The model assumed that a lowering of the availability factor of Colorado's coal-fired generating fleet from 85 percent to 65 percent would not present an operational or equipment challenge. When lowering the availability factor was modeled as a sensitivity, it created a need for an additional 1,600 MW of new gas-fired generation and an additional 300 MW of wind generation.

The model also conducted two sensitivity runs for gas prices; one at 30 percent higher and one at 30 percent lower than gas prices in the reference scenario to gauge the fuel price impact on the grid mix. The higher gas prices on the mix of capacity additions were minimal, with only 50 MW more wind being added than in the reference case. Low gas prices had no impact on renewable capacity additions compared to the reference scenario but had more impact on adding more gas-fired generation. The model determined that the low gas sensitivity resulted in the selection of 550 MW of advanced combined cycle (ACC) and 320 MW of a more advanced gas-fired generation technology available in 2017, that would hypothetically capture 90 percent of the CO_2. When the model introduced the REDI Project's 20x20 goal to sensitivity runs, the picture changed. About 2.50 GW less wind is required for low gas prices but about 870 MW more gas-fired generation is added. High gas prices reduced gas-fired generation by 380 MW but added 180 MW more wind compared to reference scenario with 20x20.

The assumptions used in the MARKAL study are transparent to interested audiences. A detailed report on the MARKAL study for the REDI Project is available on the REDI portion of the GEO website.[143]

The chart on the previous page provides key assumptions used in the modeling. "NA" (not applicable) is stated as such either because the data is not applicable, or that the generation resource indicated was not modeled.

Appendix II. Terminology

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

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.

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.

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).

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.

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.

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

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.

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.

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.

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

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.

Renewable energy resources: Energy resources which are naturally replenishing in a relatively short period of time, such as solar energy, geothermal energy, wind energy, biomass, and hydropower.

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 1) the adequacy of the transmission system to accommodate a request for either firm point-to- point transmission service or network integration transmission service and 2) whether any additional costs may be incurred in order to provide transmission service.

Transmission Customer: Any eligible customer (or its designated agent) that 1) executes a service agreement, or 2) 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

Watt: A unit of electrical power.

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.

Endnotes

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3 http://en.wikipedia.org/wiki/Electricity_sector_of_the_United_States

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12 http://www.xcelenergy.com/SiteCollectionDocuments/docs/Section%203_Forecast_Final.pdf

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15 http://epw.senate.gov/public/index.cfm?FuseAction=Majority.WelcomeMessage

16 http://www.epa.gov/climatechange/endangerment.html The EPA decision is based on an April 2007 U.S. TuesdSupreme Court ruling that the government could limit greenhouse gases under federal law if it found them a danger to the public health and welfare. The high court ordered the EPA to make a determination. Former President George W. Bush declined to act, passing the issue on to President Obama.

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47 June 16, 2009 Denver Post interview

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51 http://www.ases.org/index.php?option=com_content&view=article&id=565&Itemid=23

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78 Data provided by PSCo.

79 Electric Reliability Council of Texas, "Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study," April 2, 2008. See discussion of Scenario 2, pp. 24-25.

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107 http://www.trans-elect.com/

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109 http://www.ucsusa.org/assets/documents/global_warming/climate-2030-report.pdf

110 http://www.dsireusa.org/

111 California Public Utilities Commission, "Renewables Portfolio Standard Quarterly Report," quarterly report to the state legislature, First Quarter 2009.

112 http://www.energy.ca.gov/reti/index.html

113 The WREZ study applied more rigorous screening criteria than did the *SB07-91 Report*, therefore the WREZ capacity estimates for Colorado are smaller. The WREZ estimates represent only those resources of high enough quality to be reasonably competitive for regional export; they do not include lower quality resources that may still be economic if developed for in-state demand. In addition, the WREZ estimates include developability adjustments. Developable wind resources were assumed to be 25% of the technical wind potential; developable solar resources were assumed to be 3.5% of the technical solar potential. The SB-091 estimates do not include developability adjustments.

114 www.westgov.org/wga/initiatives/wrez/

115 http://wind.nrel.gov/public/WWIS/

116 FERC Order, WestConnect (Docket No. ER09-409), February 10, 2009

117 http://www.dora.state.co.us/puc/DocketsDecisions/HighprofileDockets/09A-325E.htm

118 http://engage.edaw.com/socotransmission/map

119 http://www.coloradocollaboratory.org/

120 http://www.westernresourceadvocates.org/energy/pdf/SmartLines_Final.pdf

121 see www.colorado.gov/energy

122 http://www.hollandhart.com/articles/Transmission_Siting_White_Paper_Final.pdf

123 The PUC has authority regarding the issuance of a CPCN, but not regarding determining siting, unless through the appeals process.

124 http://www.colorado.gov/energy/index.php?/utilities/category/renewable-energy-development-infrastructure/

125 http://www.wapa.gov/transmission/eptp/landowner.htm

126 "Last Stand For Climate Bill This Year? Senate hearing starts with little chance of passage before treaty talks" by: the Associated Press, 27 Oct 2009.

127 http://www.ferc.gov/news/headlines/2009/2009-4/10-28-09-transmission-MOU.pdf

128 http://www.govtrack.us/congress/billtext.xpd?bill=s111-1733

129 http://www.ferc.gov/EventCalendar/Files/20091027115535-Wellinghoff-10-27-09.pdf

130 http://www.nationalwind.org/assets/publications/ferc890.pdf#xml=http://pr-dtsearch001.americaneagle.com/service/search.asp?cmd=pdfhits&DocId=131&Index=F%3a%5cdtSearch%5cnationalwind&HitCount=10&hits=7+8+9+a+9f9+a24+a2e+a60+b2a+b6b+&hc=488&req=mean+for+the+west

131 http://www.necpuc.org/ppt/Kirkwood2009.pdf

132 http://www.naruc.org/Testimony/09%200612%20Coen_Trans_Testimony1.pdf

133 WAPA will help build the $213 million Montana-Alberta Tie Limited (MATL) transmission project between Great Falls, Montana, and Lethbridge, Alberta.

134 http://www.nerc.com/

135 http://www.nerc.com//files/2009_LTRA.pdf

136 Issues involved in the creation of such an institution were the subject of a legal symposium entitled "Multistate Decision Making for Renewable Energy and Transmission" was attended by 170 people on August 11, 2009 in Denver. The event was organized by NREL and the DOE in collaboration with state utility commissioners from Colorado, New Mexico, Utah and Wyoming. The papers presented will be published ßin the spring 2010 issue of the University of Colorado Law Review.

137 http://www.redorbit.com/news/business/1275416/xcel_energy_to_test_wind_energy_battery_storage/index.html

138 http://apps1.eere.energy.gov/news/progress_alerts.cfm/pa_id=200

139 http://www.energy.gov/news2009/8280.htm

140 http://www.nrel.gov/wind/systemsintegration/pdfs/2008/porter_state_transmission_authorities_poster.pdf

141 http://www.colorado.gov/energy/index.php?/utilities/category/clean-energy-development-authority/

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