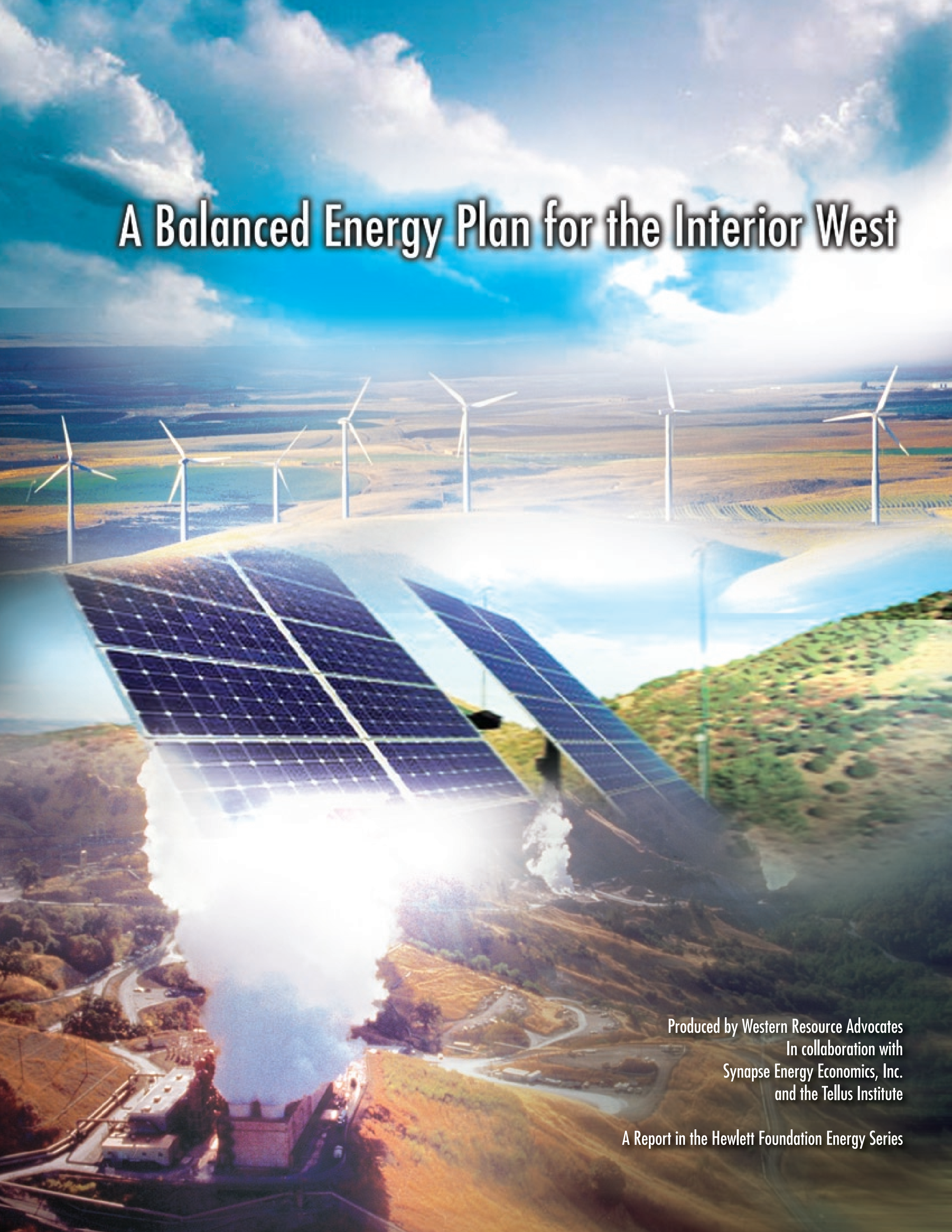
A Balanced Energy Plan for the Interior West



Produced by Western Resource Advocates
In collaboration with
Synapse Energy Economics, Inc.
and the Tellus Institute

A Report in the Hewlett Foundation Energy Series

Foreword

Since 1991, Western Resource Advocates (WRA), formerly the Land and Water Fund of the Rockies, has promoted a vision of the western electric system that lowers electricity costs, reduces economic risk and protects the environment of the Interior West. This report updates that vision, focusing on the cost savings and reduced risks resulting from a more diversified mix of electric resources.

This report was made possible by a generous grant from the William and Flora Hewlett Foundation, whose support in many ways is essential to WRA's work. We are especially grateful to Rhea Suh for her encouragement and support throughout this project. Additional funding was provided by the Department of Energy's Denver Regional Office. We thank Cathy Iverson for her support.

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WRA is also grateful for the guidance, advice, and feedback provided by the Balanced Energy Plan Advisory Committee. The committee members are listed here with their professional affiliation. Participation on the Advisory Committee does not imply an endorsement or support for this report or its findings by either the individuals or their organizations.

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This report is dedicated to the memory of Steve Bernow, a founder and Vice President of the Tellus Institute. Throughout his career Steve made substantial contributions to a wide range of energy and environmental topics, with an emphasis on strategies for controlling global warming, encouraging energy efficiency and renewable resources, and making the world safer and more equitable for future generations. Steve brought a remarkable amount of passion, warmth and humor to his work, and all those who worked with him will miss him.

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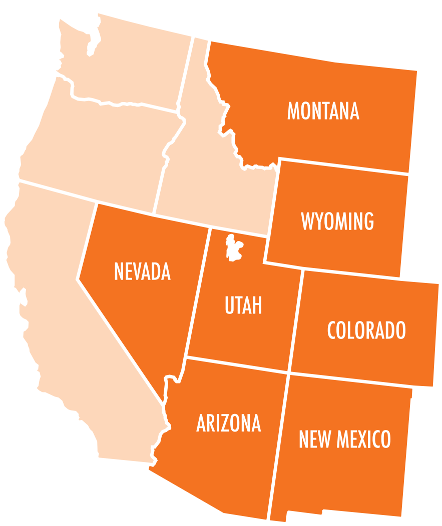
Source: Tom Hall/DOE

Foote Creek Rim wind farm, Wyoming

Introduction

This report describes a Balanced Energy Plan for the Interior West region of Arizona, New Mexico, Nevada, Utah, Colorado, Wyoming and Montana. The plan shows how energy efficiency, renewable energy and combined heat and power resources can be integrated into the region's existing power system to meet growing electric demands in a way that is cost-effective, reduces risk, is reliable, and improves environmental quality.

A computer model of the western electricity grid was used to compare the costs, transmission requirements, reliability and environmental implications of the Balanced Energy Plan with a "Business as Usual" (BAU) approach that assumes the region continues to rely almost exclusively on coal and natural gas power plants to meet its growing electricity needs. Both cases are evaluated under a range of future scenarios designed to test how each affects future costs and risks facing electric utilities and their customers.



The seven-state Interior West region that is the focus of this study is characterized by an electric system based on fossil fuels (primarily coal), a rich endowment of renewable wind, solar, geothermal and biomass resources, and a significant but largely untapped potential to use electricity more efficiently.

Compared to the BAU scenario, the analysis shows that by 2020 the Balanced Energy Plan will:

- Lower the costs of electricity production in the region by $2.0 billion per year
- Save the region up to $5.3 billion per year in the event of higher natural gas prices, stricter future environmental regulations or prolonged drought
- Provide equivalent levels of electric system reliability
- Reduce carbon dioxide emissions associated with global warming by over 40 percent
- Reduce smog- and haze-forming pollutants by over 30 percent
- Decrease power sector water consumption

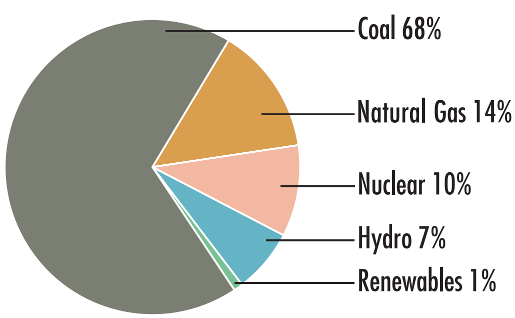
The report is divided into four chapters. Chapter 1 describes the economic and environmental risks and costs inherent in an electric system that relies mainly on fossil fuels. Chapter 2 assesses the region's energy efficiency, renewable energy and combined heat and power resource potential. Chapter 3 provides the economic and technical basis of the Balanced Energy Plan. It first describes how a portion of the resource potential identified in Chapter 2 can be added to the existing electric system in a cost-effective and reliable way and then discusses the benefits of the Balanced Energy Plan relative to BAU. Chapter 4 outlines barriers to the Balanced Energy Plan and provides examples of innovative private and public sector actions currently being taken to overcome these barriers and move the region toward a more balanced energy future. Drawing from these examples, the chapter offers several guidelines for implementing the plan in the years ahead.

The Problem: Meeting Growing Power Needs in an Uncertain and Risky World

By 2020, the Interior West is expected to need roughly 28,000 megawatts (MW) of new electric generating capacity to satisfy customer demand in the region and to continue electricity exports to California and the Pacific Northwest. This is enough power for five new cities the size of the Denver metro area.

Today, the region relies mainly on fossil fuels to generate its electricity (Figure ES-1). Coal is the largest source of power, accounting for 68 percent of the electricity produced in the region, while natural gas has been the fastest growing. Between 1990 and 2002 natural gas-fired generation in the region more than tripled. Natural gas now provides 14 percent of the region's electricity generation, up from only 4 percent ten years ago. Most of the rest of electricity production comes from nuclear and hydroelectric plants. Renewable wind, solar, geothermal and biomass resources today account for only 1 percent of the region's electricity generation.

Fig. ES-1. 2002 Electricity Generation Mix in the Interior West



Source: Energy Information Administration. 2003. *Electric Power Annual 2002.* DOE/EIA-0348(2002).

Historically, the electric system has provided low-cost, reliable power. Increasingly, however, the current system exposes customers to the risk of increased electricity costs, due to:

- Volatile and rising natural gas prices
- More stringent environmental regulations, including limits on carbon dioxide emissions
- Reduced hydroelectric output due to prolonged drought
- An increasingly overloaded transmission system that threatens reliable power delivery

These economic risks are not the only problems associated with the current system. A non-diversified fuel mix is also at the center of many of the region's most serious public health and environmental problems, including:

- Air pollution
- Damage to western landscapes from fossil fuel extraction
- Consumption and pollution of scarce water resources
- Climate change

Clear vistas, unspoiled landscapes, and clean air and water are important in their own right. But because they are central to the quality of life that draws people to the region, they are also critical to the region's economy.

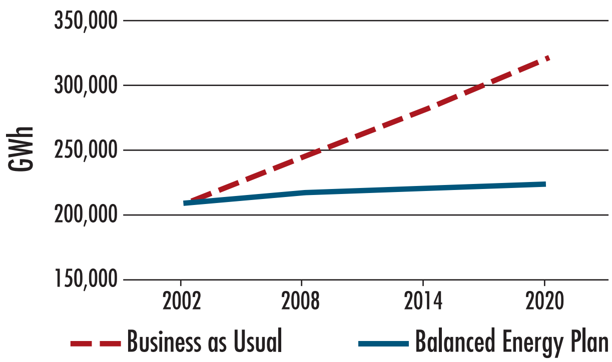
Continued investment in fossil fuel generation to meet growing power needs increases our exposure to these economic risks and environmental impacts. Yet continued fossil fuel reliance is the current trend. Between 2002 and 2005 over 10,000 MW of new natural gas generating capacity are expected to come on-line in the seven-state Interior West region. In addition, roughly 30 new coal plants, representing 25,000 MW of new generating capacity, have been proposed in the Interior West. While many of these plants are speculative, 8000 to 10,000 MW have been proposed by viable developers who are currently seeking permits and other regulatory approvals.

The Solution: A Balanced Energy Plan for the Interior West

The Balanced Energy Plan developed in this report shows how these risks can be addressed by diversifying the region's electric resources with new investments in renewable energy, energy efficiency and combined heat and power resources over a 2002-2020 study period.

Energy efficiency is at the core of the Balanced Energy Plan. Implementation of commercially available energy efficiency technologies for uses such as lighting, heating, air conditioning and industrial motors remains the region's least-cost electric resource. These new efficiency technologies can reduce energy consumption without impairing the level or quality of the electric services we need. Figure ES-2 shows the electricity consumed in the region under the BAU case and under the Balanced Energy Plan. By 2020, the Balanced Energy Plan meets the region's needs with 30 percent less electricity than Business as Usual.

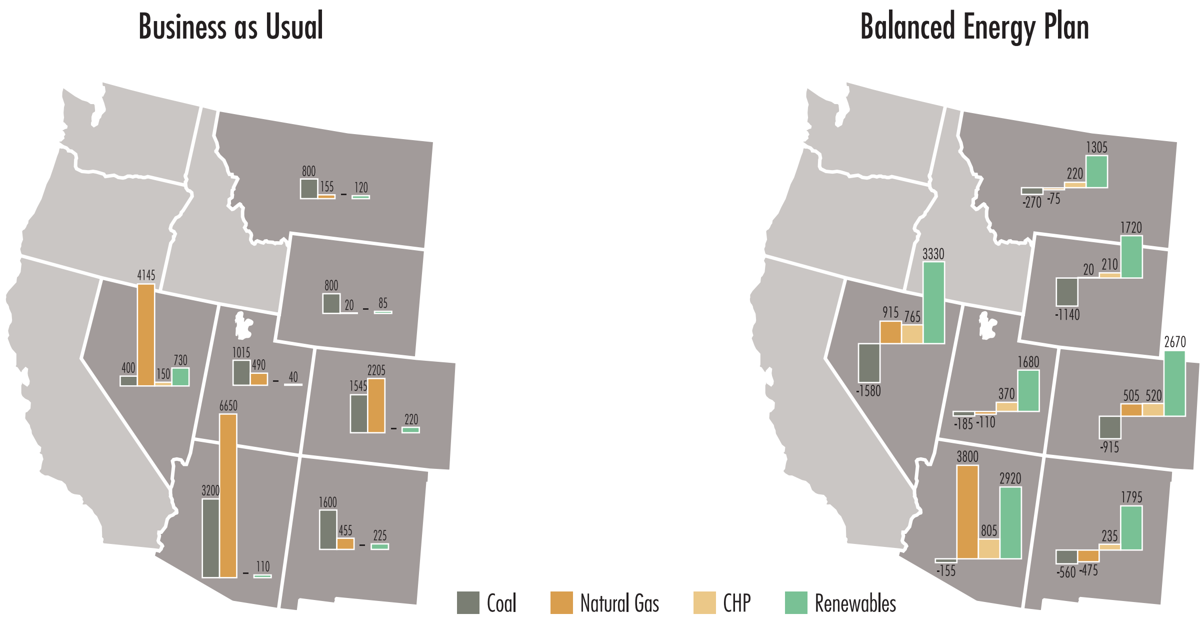
Fig. ES-2. Electric Load Growth in the Interior West: Business as Usual & Balanced Energy Plan



Renewable energy and combined heat and power generation are the other key components of the Balanced Energy Plan. Combined heat and power projects are facilities that produce both electricity and useful thermal energy in a single integrated system. By 2020, the Balanced Energy Plan adds 15,410 MW of renewable capacity and 3135 MW of combined heat and power to the region's electric system.

The Balanced Energy Plan also adds 7815 MW of gas-fired generation that were already under construction in 2002 and scheduled to be on-line by 2004. In addition, the plan retires 8050 MW of existing coal and natural gas-fired power plants. Of this amount, 2595 MW are plants retired at the end of their expected useful lives. The remaining 5455 MW are early retirements of less efficient, more polluting power plants.

Fig. ES-3. Net Capacity Additions by 2020: Business as Usual and Balanced Energy Plan



Note: Figures rounded to nearest 5 MW.

By contrast, the Business as Usual case adds 26,075 MW of coal and natural gas-fired power plants to the region's existing power base. Of this capacity, 16,075 MW are expected to be natural gas plants and 10,000 MW are expected to be conventional coal power plants. The BAU case also includes 1530 MW of renewable energy. Like the Balanced Energy Plan, the BAU case retires 2595 MW of natural gas and coal plants that reach the end of their expected lives during the study period. However, the BAU case does not retire any plants early.

Fig. ES-4. Regional Electric Generation Mix in 2020

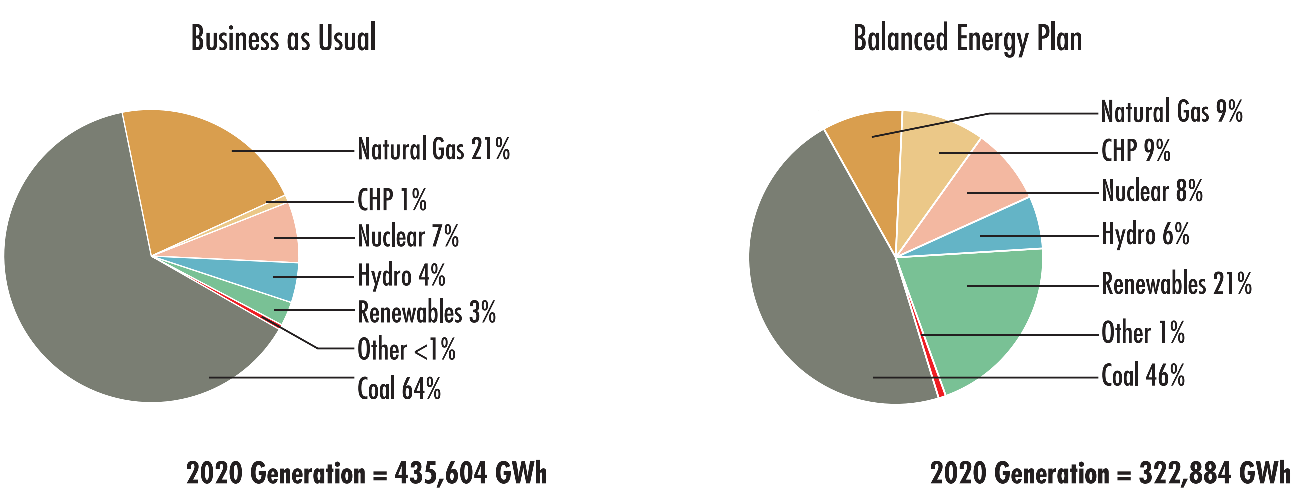


Figure ES-3 shows the resource additions by 2020 under both the BAU case and the Balanced Energy Plan. Figure ES-4 compares the regional generation mix that results in 2020 under each scenario.

By 2020, under the Balanced Energy Plan, renewable resources provide about 20 percent of electricity generation in the Interior West and combined heat and power provides about 9 percent. This compares to 3 percent renewable energy generation and 1 percent combined heat and power generation under BAU.

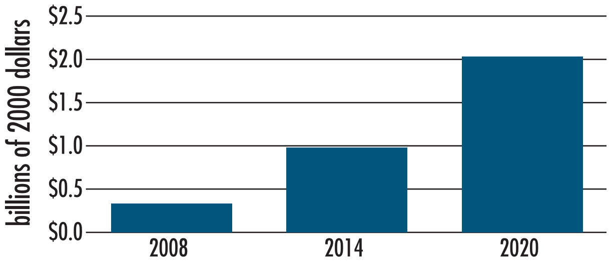
Evaluating the Balanced Energy Plan

The PROSYM computer model of the western electricity grid – often used by electric utilities to evaluate their own resource acquisition plans – was used to compare the Balanced Energy Plan to Business as Usual in terms of cost, risk mitigation, environmental impacts, and generation and transmission reliability.

Cost Under base case conditions, the analysis assumed that over the 2002-2020 study period natural gas prices would be in the range of $3 to $5 per million BTUs in year 2000 dollars. These prices are lower than the $5 to $6 per million BTUs the region is currently experiencing, and much lower than the $9 to $10 price spikes that have occurred within the last three years. In addition, the base case analysis assumes that no carbon dioxide regulations will be imposed and that hydroelectric conditions will be normal.

Under these conditions, the Balanced Energy Plan saves customers $0.3 billion in 2008 and $2.0 billion in 2020. Figure ES-5 shows

Fig. ES-5. Balanced Energy Plan Savings Relative to Business as Usual



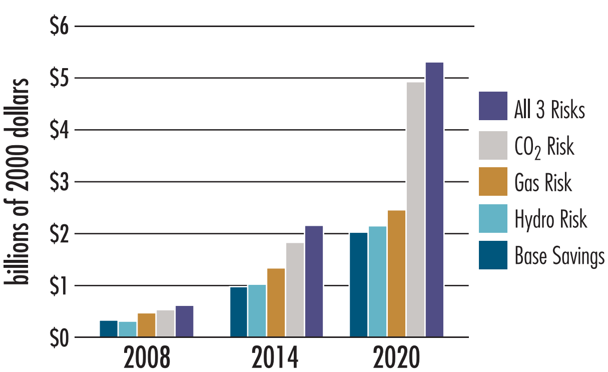
the annual savings of the Balanced Energy Plan relative to BAU under our base case assumptions.

Risk Mitigation To compare how the Balanced Energy Plan and the BAU case respond to uncertainty and risk, we evaluated each plan under higher natural gas prices, future carbon dioxide regulations, and lower hydroelectric production due to prolonged drought. Two of these risks – higher natural gas prices and lower hydro output – were important factors contributing to the electricity crisis that originated in California and spread across the West during 2000 and 2001.

Natural gas price risk was analyzed by assuming a 25 percent increase above the base case gas price forecast. Carbon dioxide regulatory risks were analyzed assuming an emissions cap-and-trade program would impose a cost of $5 per ton of CO_2 in 2008, increasing to $20 per ton by 2020. These costs fall in the middle range of recent studies estimating the cost of complying with future carbon dioxide regulations. Risk of reduced hydro output due to drought was analyzed by assuming a 20 percent reduction in water conditions relative to a normal water year. Historically, 10 percent of years experience this level of drought or worse. We also analyzed a combined scenario in which all three of these risky events were assumed to occur simultaneously.

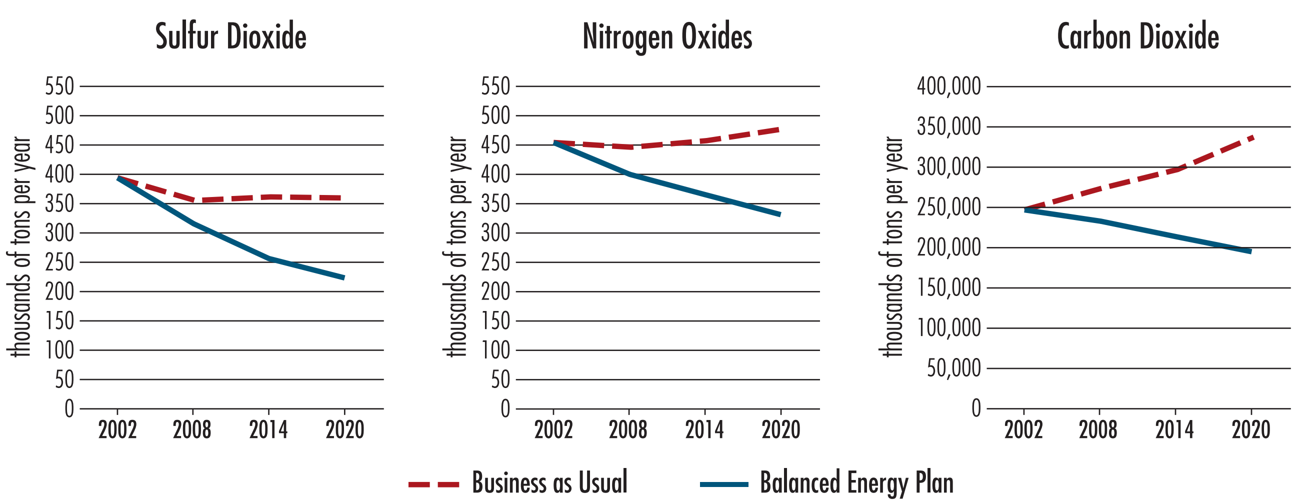
Under each of the risk scenarios, the Balanced Energy Plan performs better than BAU. In 2014, compared to BAU, the plan saves the region at least $1 billion per year in lower electricity production costs if any of the risks occur. In 2020, in the combined-risk scenario, the Balanced Energy Plan saves the region $5.3 billion per year. Figure ES-6 shows the savings resulting from the Balanced Energy Plan under the various risk scenarios.

Fig. ES-6. Risk Scenarios: Balanced Energy Plan Savings Relative to Business as Usual



Environmental Impacts The Balanced Energy Plan's efficiency and renewable energy investments, along with early retirements of older and more-polluting power plants, dramatically reduce power sector air emissions. Figure ES-7 summarizes the differences between power sector emissions of sulfur dioxide, nitrogen oxides and carbon dioxide under the Balanced Energy Plan and BAU. Sulfur dioxide and nitrogen oxides contribute to a range of public health and environmental problems. Carbon dioxide is the principal greenhouse gas contributing to climate change. By 2020, the Balanced Energy Plan outperforms BAU for all three emission types. In addition to protecting public health and the environment, these reductions will help decrease the need for costly pollution controls on industrial and manufacturing facilities to comply with federal, state and local air quality requirements.

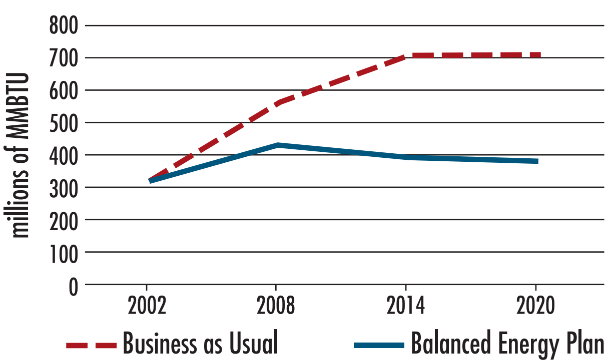
Fig. ES-7. Air Pollutant Emissions



The Balanced Energy Plan's lower level of fossil fuel generation also reduces the use of increasingly scarce and valuable water to cool power plants. We estimate that by 2020 the lower amount of coal and natural gas generation in the Balanced Energy Plan will reduce water consumption in the region by about 82 billion gallons per year, enough to serve the annual water needs of over one million urban residents.

Reduced reliance on fossil fuels can also help lessen the impacts of natural gas and coal extraction on western lands. For example, under the BAU scenario, between 2002 and 2020 annual natural gas consumption by power plants in the Interior West more than doubles. In contrast, under the Balanced Energy Plan, power plant natural gas consumption increases by only 18 percent (Figure ES-8). Similarly, by 2020, coal consumption under the Balanced Energy Plan is 42 percent lower than under BAU. This fuel savings should translate into less damage to western landscapes due to a reduced need to extract fossil fuels.

Fig. ES-8. Natural Gas Consumption by the Electric Power Sector in the Interior West



High voltage transmission lines

Reliability Absent new transmission investments or efforts to reduce power flows over the western grid, there is a mounting risk of transmission system failures and delivery interruptions to electricity consumers. Because many renewable resources, particularly wind, are in remote locations, the Balanced Energy Plan requires greater investment in major interstate transmission lines than BAU. However, because of its lower overall electricity demands due to investments in energy efficiency, the Balanced Energy Plan requires fewer local line upgrades. In the end, the lower localized transmission costs more than offset the higher interstate investments.

With regard to generation reliability, both the BAU scenario and the Balanced Energy Plan were developed to ensure that electricity demanded by consumers was available in all parts of the region during all times of the year. In the Balanced Energy Plan we paid special attention to ensuring that the intermittent wind resources did not compromise system reliability.

Toward a More Balanced Energy Future

The Balanced Energy Plan lowers energy costs, manages risk, stabilizes electric system reliability, and protects public health and the environment. As such, large industrial energy users, utilities, rural local governments, cities and, especially, future generations have an enormous stake in its implementation. However, the Balanced Energy Plan represents a departure from the conventional wisdom on how to meet electricity demands. If the plan is to be implemented it will require innovative actions from both the private and public sectors.

Businesses will need to lead the way. Businesses have a compelling need for a stable operating environment and, like all of us, for low-cost, reliable power. As importantly, businesses control the flow of most of the capital that could be invested in the technologies that are at the center of the Balanced Energy Plan. They see the opportunities, risks and benefits that these technologies can provide in their operations and markets better than anyone else.

Source: Bill Timmerman/NREL

Arizona Public Service Company's Dish Stirling Solar facility in Tempe, Arizona

Because it shapes the context in which businesses and consumers make energy investment decisions, public policy will also be important in moving the region toward a more balanced energy future. A wide variety of policies can be used to provide incentives and encourage investments in the resources comprising the Balanced Energy Plan. Some of the most important of these policies are identified in Chapter 4.

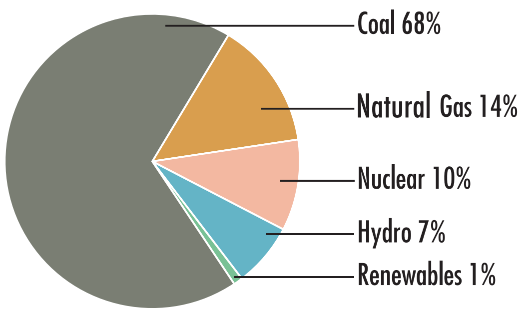
Ultimately, whether the Interior West achieves a balanced energy future depends on thousands of decisions made by utilities, independent power producers, businesses, utility customers, state regulators and many others. Our hope is that this report will help inform those decisions by making clear their associated risks, costs and environmental impacts and will start a regional dialogue on the stakes involved in the choices we make regarding our energy future.

Chapter 1 The Need for a Balanced Energy Plan for the Interior West

Introduction

Today, the Interior West – Arizona, Colorado, Montana, Nevada, New Mexico, Utah, and Wyoming – relies mainly on fossil fuels to generate its electricity. Coal is the largest source of power, accounting for 68 percent of the electricity produced in the region, while natural gas has been the fastest growing. Between 1990 and 2002 natural gas-fired generation in the region more than tripled. Natural gas now provides about 14 percent of electricity generation, up from only 4 percent ten years ago. Most of the rest of the electricity produced in the region comes from nuclear and hydroelectric plants. Renewable wind, solar, geothermal and biomass resources account for 1 percent of the regional mix.

Fig. 1-1. 2002 Electricity Generation Mix in the Interior West



Source: Energy Information Administration. 2003. *Electric Power Annual 2002.* DOE/EIA-0348(2002).

Historically, the region's electric system has provided low-cost, reliable power. Increasingly, however, electricity customers are exposed to risks such as rising and increasingly volatile natural gas prices, higher electricity costs due to potential future environmental regulations, and drought-reduced hydroelectric output.

In addition to exposing us to greater economic risks, the current electricity generation mix also contributes to some of the region's most serious public health and environmental problems, including air pollution, damage to western landscapes from fossil fuel extraction, pressure on scarce water resources, and climate change.

This chapter describes the economic risks and environmental impacts associated with relying primarily on fossil fuels to generate power. The region can manage these risks and impacts by adopting a more balanced energy plan that diversifies the current mix of resources with investments in energy efficiency, renewable energy, and combined heat and power resources.

The California Electricity Crisis: A Wake-up Call for the West

In 2000 and 2001, California faced an energy crisis characterized by rolling blackouts and skyrocketing natural gas and wholesale electricity prices. From 1999 to 2000, electricity costs in the state rose from $7 billion to $28 billion. Major utilities were forced into bankruptcy. Blackouts caused hundreds of millions of dollars of lost economic output. While California electricity customers, large and small, bore the brunt of the economic damage, the entire western power grid felt the shockwaves. Power-dependent primary industries, like aluminum smelters, were shut down, in some cases permanently, while the confidence of power-sensitive firms like computer chip manufacturers was shaken.

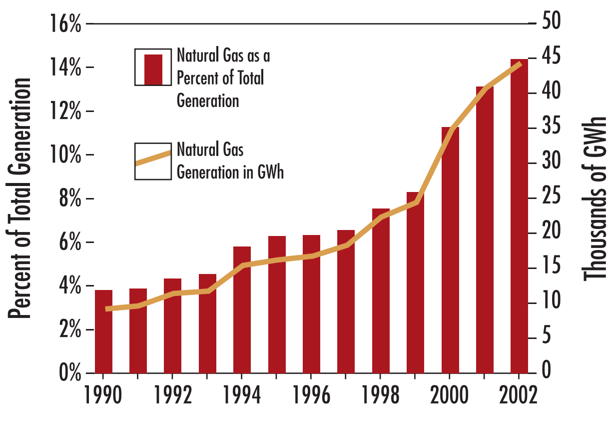
The causes of the California breakdown were multiple, but they appear to include market manipulation, a poorly formulated deregulation scheme, lower-than-expected hydroelectricity production, higher-than-expected natural gas prices, and failure to invest in sufficient new electric resources, including energy efficiency. The system simply was not sufficiently robust to absorb human missteps and unanticipated conditions, natural and otherwise.

The kind of rapidly developing firestorm that enveloped California is unlikely to occur in the Interior West. Yet there is a lesson inherent in the California crisis: we must take steps today to hedge against known risks. Otherwise, our region faces a situation in which electricity becomes more expensive than necessary and in which the environmental consequences of power production are needlessly severe.

Natural Gas Price Risk

During the 1990s the Interior West, like other parts of the country, increased its use of natural gas to generate electricity. This increase was driven by a combination of factors, including the development of new, more efficient natural gas power plants with low up-front capital costs and low air pollutant emissions, together with historically low natural gas prices during this period. Figure 1-2 shows the Interior West's growing reliance on natural gas generation over the previous decade. For the region as a whole, natural gas-fired electricity generation increased by nearly 350 percent between 1990 and 2001, while total electricity generation grew by 27 percent. The market share for natural gas grew from 4 percent in 1990 to over 14 percent in 2002.

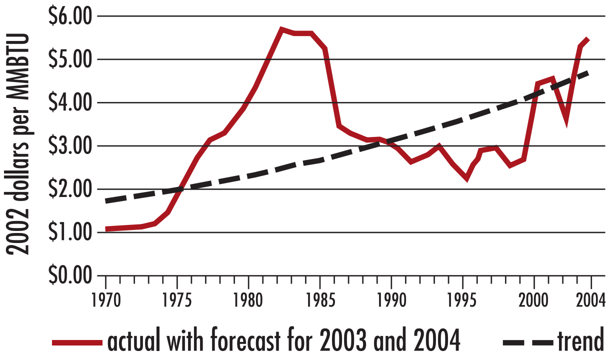
Fig. 1-2. The Interior West's Increasing Use of Natural Gas



Source: Energy Information Administration. 2003. *Electric Power Annual 2002.* DOE/EIA-0348(2002).

Increased dependence on natural gas power has exposed electricity customers to the risk of rising natural gas prices. Figure 1-3 shows prices paid by electric utilities nationally for natural gas in constant 2002 dollars. The figure highlights two

Fig. 1-3. Natural Gas Prices Paid by U.S. Electric Utilities



Sources: Energy Information Administration. *Annual Energy Review 2000.* DOE/EIA-0384(00), *Natural Gas Monthly*. April 2003. DOE/EIA-0130(2003/04), and *Short Term Energy Outlook*. March 2004.

important aspects of natural gas prices. First, they are volatile, fluctuating on average about 14 percent from one year to the next and in extreme cases by as much as 60 percent. Second, natural gas prices are trending upward at about 3 percent per year.

Rising and volatile natural gas prices are already having impacts on retail electricity prices across the Interior West. Since 2001, at least five major electric utilities in the region – Xcel Energy, Arizona Public Service Company, Nevada Power Company, Sierra Pacific Power Company and PacifiCorp – have filed for higher electric rates. In each case, higher natural gas prices were cited as important factors behind the requested increases.[1]

Despite these risks, power providers have continued to make large investments in natural gas capacity. Between 2002 and 2005 over 10,000 MW of new natural gas generating capacity are expected to come on-line in the seven-state region.[2]

Unlike natural gas prices, coal prices have remained relatively stable over the same time period. However, turning to new coal-fired generation as a hedge against rising or fluctuating natural gas prices has significant environmental impacts and increases the risk of higher costs due to potential future environmental regulations. The best way to protect the region from both volatile fossil fuel prices and future environmental liabilities is to diversify our energy portfolio with a reasonable proportion of resources that do not have fuel costs associated with them and that also have low environmental impacts. Energy efficiency and renewable resources meet these criteria and are discussed in more detail in Chapters 2 and 3.

Environmental Impacts and Regulatory Risks of Fossil Fuel Generation

Environmental regulatory risk is the risk that future, stricter environmental regulations will be enacted that raise electricity costs. The more our electricity generation relies on fossil fuels, the greater the risks of costly environmental regulation. A more diversified energy portfolio can hedge against these economic liabilities. The following section discusses environmental impacts of fossil fuel generation and assesses regulatory risks associated with each.

Climate Change Impacts

Fossil fuel combustion accounts for about three-quarters of human-caused emissions of carbon dioxide (CO_2), the main greenhouse gas linked to climate change.[3] While there has been some disagreement among scientists about the extent and cause of climate change, the overwhelming scientific consensus is that the Earth's climate is changing as a result of human activities. Most gases associated with climate change are also naturally occurring, but the weight of scientific evidence indicates that observed increases in greenhouse gases are attributable to human sources.

In 2001, the Intergovernmental Panel on Climate Change released its *Third Assessment Report – Climate Change 2001*. The report observed that global average surface temperature had increased over the twentieth century by about 0.6º C. It also found that the 1990s were the warmest decade on record, and 1998 was the warmest year. Explaining this warming trend, the IPCC concluded "there is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities."

Worldwide, rises in sea level due to climate change would be particularly damaging, affecting millions of people living in coastal areas, especially in the developing world. The risks of rising sea levels and their impacts on the developing world are a strong reason for taking action to address global climate change.[4]


Source: Walt Hester

Scientists have attributed the decline of the pika to the impacts of climate change on alpine ecosystems.

The impacts of climate change on the Interior West could also be significant. The U.S. Environmental Protection Agency (EPA), in its *U.S. Climate Action Report 2002*, evaluated the potential impacts on the United States if projected warming trends materialize. The report projected several costly and disruptive climate change impacts on the Interior West:

- More rain and less snow during the winter, leading to reduced snowpack. This could affect water supplies and compromise the region's billion-dollar winter sports industry.
- Disappearance of alpine meadows and the ecosystems they support.
- More frequent and severe wildfires.
- Flooding due to extended rainy seasons.
- Loss of cold-water fish, such as trout, from Rocky Mountain fisheries.

Other impacts could be beneficial, including improved agricultural and forest productivity. Precipitation may increase in some areas, including the Southwest, leading to a transition of certain areas from desert to grasslands, but increased precipitation could be accompanied by higher temperatures, more extreme wet weather events and prolonged droughts, and increased risk of forest fires.

Because of its reliance on fossil fuels, the electric industry in the Interior West is a significant source of carbon dioxide emissions. In 2002, power plants in the region emitted approximately 255 million tons of carbon dioxide – a 20 percent increase from 1990 levels. Today power plants in the region account for roughly 10 percent of U.S. carbon dioxide emissions while generating about 8 percent of the country's electricity.[5]

Climate Change Regulatory Risk

With mounting scientific evidence that human activity is contributing to climate change, it is becoming increasingly likely that the electric utility industry will face carbon dioxide regulation in the future. If liability for costs associated with climate change is assigned to industries that emit carbon dioxide, a large portion of the regulatory burden will fall on electric utilities and their customers.

Many American companies are already making voluntary commitments to reduce their carbon risks. Companies such as 3M, Eastman Kodak, General Motors, IBM, Pfizer, and Johnson & Johnson are participating in EPA's Climate Leaders program to develop and meet greenhouse gas reduction goals. The nation's ski areas are also concerned about climate change and the negative impact it could have on their business. In March 2004, sixty-six ski resorts, including 20 in the Interior West, submitted a letter of support for the Climate Stewardship Act sponsored by Senators McCain and Lieberman.

Evidence of concerns about future carbon dioxide regulations also comes from electric utility shareholders and from power companies themselves. Shareholders have filed resolutions on greenhouse gas emissions with American Electric Power, Cinergy, Pacific Gas and Electric, Southern, TXU, and Xcel Energy, according to the Shareholder Action Network. In February 2004, American Electric Power and Cinergy agreed to publicly report their exposure to risks due to potential future regulations to limit greenhouse gas emissions. In evaluating new generating resources, PacifiCorp, a major power company serving parts of Utah, Wyoming, Washington, Oregon, Idaho and California, includes an $8 per ton carbon dioxide cost adder when evaluating the costs of new natural gas and coal power plants.

Action on Climate Change by U.S. Power Companies

American Electric Power will cap CO_2 emissions at the average of 1998-2001 levels and reduce or offset them by a cumulative 10 percent over the period 2003-2006.

Cinergy Corp. pledged to reduce greenhouse gas emissions to an average of 5 percent below 2000 levels during the period 2010-2012.

DTE Energy committed to reducing greenhouse gas emissions by 5 percent from 1999 levels by 2005.

Entergy will stabilize CO_2 emissions at 2000 levels through 2005.

PSEG committed in 1993 to stabilize CO_2 emissions from power plants in New Jersey at 1990 levels by 2000. They have achieved this goal while generating 2 million more megawatt-hours in 2000 than in 1990.

Most of the rest of the industrialized world has already begun developing regulatory strategies for reducing carbon dioxide and other greenhouse gas emissions. In the U.S., action is starting at the local and regional level. In New England, states have begun developing enforceable limits on greenhouse gas emissions from power plants. On the West Coast, California, Oregon and Washington have agreed to act jointly to develop strategies to reduce greenhouse gas emissions. Oregon and Washington regulate carbon dioxide emissions from new power plants. Oregon's Energy Facility Siting Council sets CO_2 standards for new power plants, and Washington recently enacted a law requiring new power plants to mitigate 20 percent of their CO_2 emissions. In the Interior West, several communities, including Albuquerque; Salt Lake City; Aspen, Boulder, Denver and Fort Collins, Colorado; and Mesa and Tucson, Arizona have adopted goals for greenhouse gas emission reductions through the Cities for Climate Protection program of the International Council for Local Environmental Initiatives.

While the federal government does not regulate carbon dioxide as a pollutant, there is pressure to move in this direction. In October 2003, 12 states, three major metropolitan areas, one island government, and several environmental groups petitioned EPA to regulate carbon dioxide. Their legal challenge alleges that the federal government acknowledges the negative impacts of climate change but has failed to regulate emissions.[6]

In Congress Senators John McCain and Joseph Lieberman introduced the McCain-Lieberman Climate Stewardship Act in 2003 and again in 2004. The act would require all sectors of the U.S. economy to limit greenhouse gas emissions to year 2000 levels by 2010. Although the bill did not pass in 2003, the 43-to-55 vote was much closer than anticipated. Other bills such as the Clean Air Planning Act of 2002 and the Clean Power Act also included carbon dioxide limitations.

Continued investment in fossil fuel power plants, particularly new conventional coal plants, expose utilities and their customers to increased electricity costs due to potential future carbon dioxide regulation. Retrofitting a conventional coal plant with equipment to capture carbon dioxide would increase the cost of electricity from the plant by anywhere from 58 to 100 percent.[7]

While it is likely that any future regulations to limit carbon dioxide would be designed to provide flexibility and minimize compliance costs, regardless of the regulatory approach used, fossil fuel power plants, and conventional coal plants in particular, would see the greatest cost impacts. Chapter 3 analyzes the extent to which a more diversified, less carbon-intensive generating mix that includes significant amounts of renewable energy, energy efficiency and combined heat and power can reduce this risk.

Air Pollution Impacts

Fossil fuel power plants are a major source of air pollution in the Interior West. Of principal concern are emissions of sulfur dioxide, nitrogen oxides and mercury.

Sulfur dioxide and nitrogen oxides contribute to a variety of public health and environmental problems, including asthma and other respiratory disorders, regional haze, and ecosystem damage.

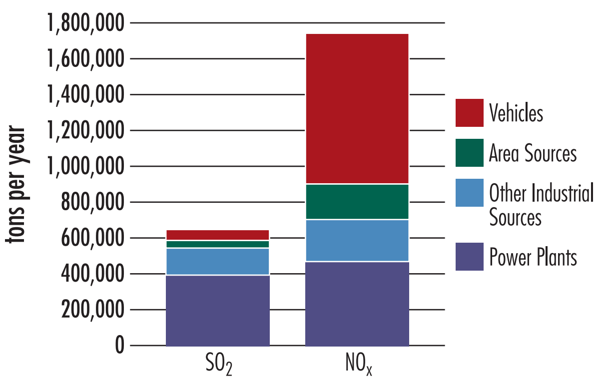
Figure 1-4 shows regional sulfur dioxide and nitrogen oxide emissions by source category. In 2002 power plants produced 61 percent of sulfur dioxide emissions and 27 percent of nitrogen oxide emissions.

Both sulfur dioxide (SO_2) and nitrogen oxides (NO_X) react in the atmosphere to form fine particles which affect human respiratory and cardiovascular systems. The respiratory effects associated with fine particle pollution include asthma attacks, bronchitis, and decreased lung function, while cardiovascular system effects include heart attacks and cardiac arrhythmias.[8]

Nitrogen oxide emissions also contribute to the formation of ground-level ozone, often referred to as smog. Ozone can damage lung tissues, aggravate respiratory disease and make people more susceptible to respiratory infection. Several major metropolitan areas in the Interior West, including Denver, Phoenix, and Salt Lake City, are experiencing rising ozone levels.

Ozone pollution is also no longer just an urban problem. Many rural areas of the West are experiencing high ozone concentrations, in some cases due to transport from urban areas and in others due to sources in the immediate vicinity. For example, the Farmington, New Mexico area in the Four Corners region is approaching a violation of the ozone national ambient air quality standard.[9] While vehicles are the major source of NO_X emissions in the West, emissions from power plants also contribute to the ozone problem.

Fig. 1-4. SO_2 and NO_x Emissions in the Interior West by Source Category*



*Emissions data are for 2002, except for vehicle emissions, which are 2003 projections based on 1996 base year emissions inventory.

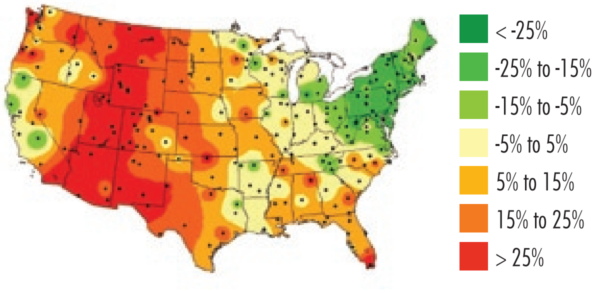
Source: E.H. Pechan and Associates. 2003. *WRAP Interim 2002 Point and Area Source Estimates: Technical Memorandum* (prepared for the Western Governors' Association); WRAP. 2003. *Regional Technical Support Document for the Requirements of Section 309 of the Regional Haze Rule.*

The same fine particles that harm public health also blur western vistas by scattering and absorbing light. As major emitters of particle-forming sulfur dioxide and nitrogen oxides, power plants contribute to haze in the West. Sulfur dioxide, in particular, has significant adverse impacts on visibility.[10] The Western Regional Air Partnership, an organization of states and tribes working to address western air quality problems, has documented that, as the largest source of SO_2 emissions in the region, coal-fired power plants are a major contributor to reduced visibility in the West.[11]

Source: National Park Service

The Grand Canyon on good, average and poor visibility days.

Fig. 1-5. Percent Change in Nitrate, 1985–2001



Source: Nilles, M. and B. Conley. 2001. Changes in the Chemistry of Precipitation in the United States, 1981–1998. *Water, Air & Soil Pollution* 130: 409–414.

Power plant SO_2 and NO_X emissions can also damage sensitive ecosystems, through acid rain and excess nitrogen-loading in soils and water bodies. Figure 1-5 shows the results of a recent U.S. Geological Survey report concluding that nitrogen deposition is increasing across much of the Interior West. The increase in nitrogen can lead to algal blooms in lakes, decreased soil fertility and changes in vegetation.[12]

Mercury emissions from power plants are also emerging as an important public health and environmental issue both nationally and regionally. When mercury enters water, it can accumulate to toxic levels in fish and in animals that eat fish. Humans can be exposed to mercury contained in fish, which can lead to birth defects. Figure 1-6 shows fish consumption advisories due to mercury contamination in the Interior West. The table also shows that the geographic extent of fish advisories can be significant in some states. For instance, over 75 percent of lake acres in Montana are currently under fish consumption advisories, 96 percent of which are attributable to mercury. Coal-fired power plants are the largest source of mercury emissions in the country, and the only major source not regulated by the government. Nationwide, coal power plants emitted an estimated 48 tons of mercury in 1999, of which plants in the Interior West states emitted 3.7 tons or 7.7 percent.[13]

Air Pollution Regulatory Risk

Compliance with existing and future air pollution regulations exposes electricity customers to the risk of higher electricity costs. Under the Clean Air Act, utilities already comply with sulfur dioxide, nitrogen oxides, and particulate requirements, but stricter requirements may be applied in the future.

Fig. 1-6. Fish Consumption Advisories in the Interior West

State	Number of fish consumption advisories *	Percentage of lake acres under advisory	Number of fish consumption advisories due to mercury	Percentage of total fish consumption advisories due to mercury
Arizona	8	<0.1%	5	63%
Colorado	11	12%	8	73%
Montana	26	76%	25	96%
Nevada	2	<0.1%	2	100%
New Mexico	26	20%	26	100%
Utah	3	<0.1%	0	0%
Wyoming	0	0%	0	–

* for all chemical contaminants.

Source: EPA. 2003. National Listing of Fish and Wildlife Advisories Fact Sheet. http://map1.epa.gov.

At the national level, several multi-pollutant legislative proposals have been made that call for reductions in power plant emissions of sulfur dioxide, nitrogen oxide, mercury and, in some cases, carbon dioxide.[14] The Environmental Protection Agency has established regional haze regulations that will require coal-fired power plants to reduce SO_2 and NO_X emissions over the next decade. EPA has also proposed new regulations to reduce power plant mercury emissions, to be finalized by the end of 2004. Increasing ozone levels across the West and growing concerns about ecosystem damage resulting from nitrate deposition place additional pressure on regulators to reduce NO_X emissions.

The risk of electricity cost increases from future pollution regulation can be reduced through diversified energy portfolios that add significant clean energy resources to the generation mix. Lowering power sector emissions with clean energy investments can also decrease the need to add costly pollution controls to other industrial and manufacturing facilities to comply with federal, state and local air quality requirements.

Quantifying Air Pollution Regulatory Risk

As part of its 2003 resource planning process, PacifiCorp analyzed the cost of meeting present, pending and future SO_2, NO_X and mercury regulations. The company estimated that in present value terms, the costs of air pollution compliance would range between $500 million and $1.7 billion, depending on the stringency of future regulations.[15]

Water Impacts

Fossil fuel electricity generation places added stress on scarce water resources in the Interior West. As part of the cooling process, coal and gas steam-generating electric plants in the region currently withdraw over 650 million gallons of water every day, totaling over 728,000 acre-feet each year. Coal plants are the power sector's primary water consumers.[16] Over half of the water withdrawn is consumed in the cooling process. The remainder is discharged into nearby waterways, often at a higher temperature or in a degraded state, which can injure aquatic and riparian wildlife.

The coalbed methane development underway in the region, described in more detail below, also has significant impacts on water quality. Coalbed methane is extracted by drilling into underground coal seams to release groundwater pressure that holds methane molecules in place. When water is removed, methane molecules pool together and rise to the surface. A typical well in Wyoming removes an average of 13,000 gallons of groundwater from coal seam aquifers each day. Some areas, such as Wyoming's Powder River Basin, are slated for more than 50,000 such wells, which means a water discharge rate of around 650 million gallons a day just for that area.[17] Coalbed water is often high in salinity and, if not properly recharged into aquifers, can impair neighboring crop and rangelands and riparian systems.

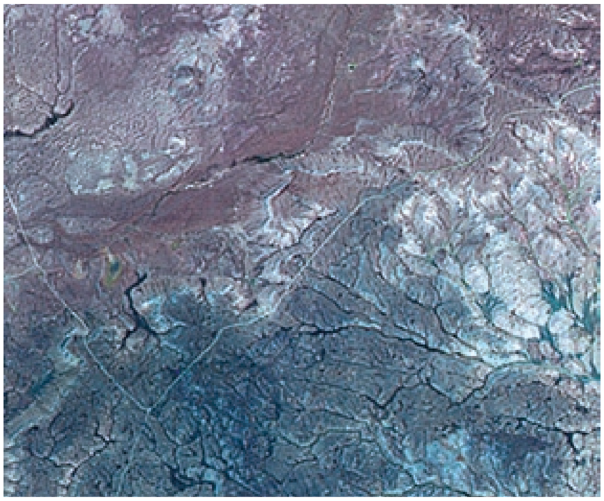
Water Regulatory Risks

While climate and air pollution regulations pose the greatest cost risks to electricity customers, they are not the only potential liabilities. Growing pressure on scarce water resources across the West raises risks that fossil fuel power plants may need to buy additional water rights for cooling purposes or adopt dry cooling technologies to reduce water consumption. Either option would increase power production costs. In 2001, the Arizona Corporation Commission decided to halt two proposed gas-fired power plants because of water considerations. One of the plants, the 720 MW Big Sandy facility, would have pumped 5267 acre-feet of water annually from an aquifer. The proposal was denied because of concerns about the potential effects this groundwater use would have on the aquifer.[18]

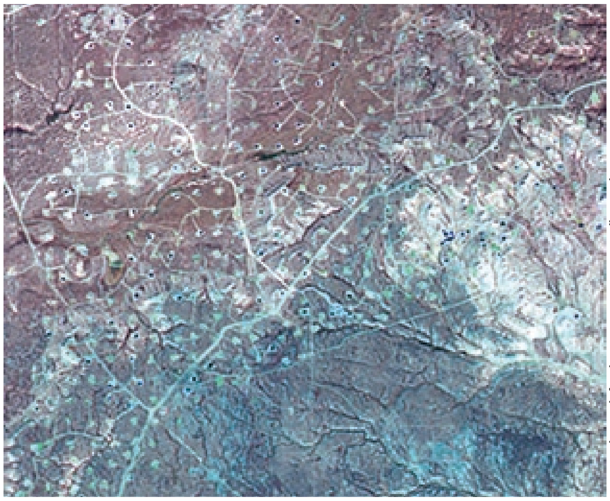
Impacts on Western Lands

The extraction of coal and natural gas for electricity production can result in significant scarring of the western landscape. Coal is mined in the West at strip mines that impact large areas of land. New roads, drill pads and other disturbances to neighboring communities and wildlife accompany natural gas production. In recent years, coalbed methane development has emerged as a new technique for the recovery of natural gas that, if not done responsibly, can have detrimental impacts on the landscape and on the rights of surface property owners. The magnitude of the natural gas and coalbed methane development proposed for the Interior West, driven in large part by rising power sector demands for natural gas, is transforming some of our public lands and rural communities into industrial zones.

Of particular concern are plans to begin drilling in some of the "last best places" in the region, such as Otero Mesa in New Mexico, the HD Mountains, the Roan Plateau and the Vermillion Basin in Colorado, and the Rocky Mountain Front in Montana. Other areas, like the Piceance Basin in Utah and Colorado, the San Juan Basin in New Mexico and Colorado, the Green River Basin in Wyoming and the Powder River Basin in Montana and Wyoming, where limited development has already occurred, face prospects of large-scale new development.



Wyoming's Upper Green River Valley, 1986



Source: Sky Truth for the Upper Green River Valley Coalition

Impacts of Natural Gas Development in the Upper Green River Valley, 2003

The accompanying photos are an example of the impacts on the land from natural gas drilling. It compares two satellite photographs of the Jonah gas field in Wyoming's Upper Green River Valley in 1986 and in 2003. The 2003 photo shows the extent of drill pads and roads related to drilling operations.

Renewable energy, energy efficiency, and combined heat and power can help limit damage to western lands by reducing the demand for natural gas from the power sector. Increased use of these resources will help protect not only rural western lands but also the economic interests of the ranchers, local governments and recreation industry who depend on these lands for their livelihoods.

Risks from Drought

Drought exposes electricity customers to risk because it can decrease the amount of hydroelectricity available to meet power demands. Hydroelectric production accounts for only 5 to 10 percent of annual generation in the Interior West, but when the entire western grid (including the Pacific Northwest and California) is considered, hydroelectricity is a much more significant resource, accounting for roughly 30 percent of total generation. Hydropower is particularly important to the grid during the summer when it provides power in times of high demand.

The West's hydropower resources fluctuate with precipitation, and output can vary greatly from year to year. Figure 1-7 shows variations in average annual stream flows for two rivers that are important regional hydropower resources: the Columbia and the Colorado.

The standard deviation of annual flows as a percentage of average flow rates indicates the high degree of stream flow variability from year to year. It is possible for flow in a given year to be 20 percent or more below average. The last column indicates the longest run of successive years where stream flow was below the long-term average. Clearly there are risks of reduced hydropower generation in dry years and there are risks of several dry years in succession.

Because hydroelectric production is a large component of the overall western power mix and because of the interconnected nature of the western power grid, a drought-induced

Fig. 1-7. Stream Flows on the Columbia and Colorado Rivers

River	Period of Measurements	Average of annual mean stream flows (cubic feet per second)	Standard deviation of annual mean stream flows (cubic feet per second)	Standard deviation as % of average	Longest run of successive years with flow < average
Columbia River, below Priest Rapids Dam, WA	1918–Sept 2001	119,515	21,477	18%	8 years: 1935–42
Colorado River, Lee's Ferry, AZ	1922–2001*	15,478	5,167	33%	14 years: 1966–79

* The years 1963 and 1964 are omitted from the Colorado River statistics because the construction of Glen Canyon Dam and installation of turbines and generators disrupted the flow of the river.

Source: U.S. Geological Survey

reduction in hydroelectric output will affect the entire western United States. Since low-cost hydroelectricity tends to keep regional power costs low when it is available in average or above-average water years, a sustained drought resulting in decreased hydropower availability will require other, more expensive generation to be substituted. This will raise electricity production costs across the West. Most of the Interior West has been in a prolonged drought for several years, and this weather pattern could continue.

Because natural gas plants are increasingly the marginal resource on the western power grid, natural gas generation is likely to be used to make up for any drought-induced reduction in hydropower. This implies a link between drought risk and natural gas price risk. In particular, if natural gas supplies are already tight and drought adds pressure to increase gas-fired generation, there will be upward pressure on natural gas prices. This feedback effect increases the overall risk to electricity customers due to reliance on natural gas.

Drought is not the only reason that output from the region's hydroelectric facilities might be reduced. Hydroelectric dams can have significant negative ecological impacts on river systems. In addition to changing water quality and temperature, dams transform a river's natural flow pattern. Maximizing dam operations to meet human needs often lowers the natural spring peak flows and increases winter base flows. This can affect river habitat, sometimes dramatically, and has caused the extinction or near extinction of several fish species. To improve habitat and restore a more natural annual flow regime, several dams have begun the process of "re-operation." Glen Canyon Dam on the Colorado River has been re-operated, and administrative efforts are underway to re-operate dams on the Green, Gunnison, and other rivers. While re-operation will improve habitat, it may reduce the ability of some hydroelectric facilities to generate power. If natural gas-fired generation is used to fill this need once again, this will increase exposure to the risk of rising natural gas prices.

The Need for a Balanced Energy Plan

In this chapter we described the economic and environmental risks and liabilities associated with relying on fossil fuels to meet most of the region's power needs. As discussed in more detail in Chapter 3, by 2020 the Interior West is expected to need roughly 28,000 megawatts of new electric capacity to satisfy growing customer demands in the region and to serve export markets in California and the Pacific Northwest. This is roughly a 50 percent increase above current levels and enough to power five new cities the size of the Denver metro area.

If the region meets these future needs through continued investment in fossil fuel generation, our exposure to these risks and liabilities will only increase. Yet continued fossil fuel reliance is the current trend. To manage risks, limit liabilities and reduce environmental impacts of the power sector, the region needs a balanced energy plan – one that diversifies the electric resource mix with increased investments in energy efficiency, renewable energy and combined heat and power resources. The remainder of this report develops such a plan and outlines the actions needed to see it realized.

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Chapter 2 Assessing the Potential for Diversified Energy Resources in the Interior West

Introduction

As a first step in developing the Balanced Energy Plan for the Interior West, we assessed the region's potential for increased use of energy efficiency, renewable wind, solar, geothermal and biomass resources, and combined heat and power technologies. This chapter shows that these resources have significant potential to meet growing electricity demands in the Interior West.

While the region has a large base of these resources to draw upon, costs were an important consideration in developing the Balanced Energy Plan. Energy efficiency is the most cost-effective energy resource available, making it an integral part of the plan. However, some renewable energy and combined heat and power technologies are more expensive than conventional generation. As described in detail in Chapter 3, in the Balanced Energy Plan these more expensive resources were pooled with energy efficiency and existing generation sources to create a diversified, reliable, low-risk, cost-effective electricity portfolio.

The Potential for Energy Efficiency in the Interior West

"Energy efficiency" refers to technologies, designs, and practices that reduce energy use without reducing the level or quality of electric services such as lighting, heating, cooling, or motive power. An energy-efficient air conditioner, for example, delivers the same level of cooling as a traditional model but uses less electricity.

Increased energy efficiency offers an attractive, cost-effective alternative to building new power plants and, in some cases, even to generating electricity from existing power plants. Many technologies and measures are available for reducing energy demand in homes, businesses, and industries. Over their lifetimes, many efficiency options save customers two to three times their cost in lower electricity bills.

To assess the potential for energy efficiency to satisfy electric service demands in the Interior West, the Balanced Energy Plan relied on a study by the Southwest Energy Efficiency Project (SWEEP) entitled *The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest*. The SWEEP study first developed a "Business as Usual" base case electricity demand forecast that assumed the continuation of current policies and trends. It then analyzed a High Efficiency Scenario that identified the electricity savings that could be achieved from the widespread adoption of cost-effective commercially available efficiency measures over the period 2003 to 2020. The study assessed the energy efficiency potential for the residential, commercial, and industrial sectors for six states in the region – Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. The Balanced Energy Plan used this High Efficiency Scenario to quantify the region's energy efficiency potential. For our study, the analysis was expanded to include Montana.

Efficiency Potential in the Residential and Commercial Sectors

For the residential and commercial sectors, SWEEP employed a "bottom up" approach that considered a range of efficiency measures for electricity uses, including lighting, cooling, and the powering of computers and appliances, and for building types such as single-family homes, multifamily homes, office buildings, retail stores, schools, and restaurants, including both existing and new construction.

To project overall electricity use in residential and commercial buildings at the state level under Business as Usual conditions, the SWEEP study started with regional growth projections from the Energy Information Administration's *Annual Energy Outlook 2002.*[1] State-by-state growth projections were developed using gross state product forecasts for the commercial sector and population growth forecasts for the residential sector. These growth projections were used to allocate future electricity use in a particular sector and state among different building types.

The energy savings potential identified in the High Efficiency Scenario was estimated by determining the proportion of buildings for which each technically feasible and cost-effective efficiency measure had not yet been installed. Efficiency measures were considered cost-effective if the costs per kilowatt-hour of saved energy were below retail electricity prices.

The identified cost-effective efficiency measures for buildings were assumed to be installed gradually during the 2003-2020 period at a rate of 4.4 percent per year. This implies that 80 percent of the identified measures would be in place by 2020. For new buildings, the SWEEP study assumed that 50 percent of cost-effective measures would be installed starting in 2003 and that this fraction would gradually rise to 100 percent in new buildings constructed in 2010 and thereafter.

Common Energy Efficiency Measures Residential and Commercial Sectors

For commercial buildings

- Efficient lamps and ballasts, including exit lighting
- More efficient air conditioners and chillers
- Duct sealing
- Reflective roofing treatments

For residences

- More efficient air conditioners
- Energy-efficient windows with dual panes with low emissivity coatings
- Additional attic insulation
- Shade trees
- Efficient lighting such as compact fluorescent lamps
- More efficient appliances such as water heaters or refrigerators

Efficiency Potential in the Industrial Sector

To estimate the energy efficiency potential in the industrial sector the SWEEP study relied on the Long-Term Industrial Energy Forecasting (LIEF) model developed at Argonne National Laboratory. The basic assumption is that industrial electricity consumption will grow over time as output grows, tempered by any changes in electricity intensity (the amount of electricity needed to produce a unit of output). Within the model, electricity intensity is influenced by three key variables related to the cost-effectiveness and adoption of energy efficiency measures:

- the assumed penetration rate of energy efficiency measures
- the capital recovery factor
- projected electricity prices

For each dollar of investment in an energy efficiency measure, the capital recovery factor is the annual principal and interest payment required to recover the investment over time at a specified interest rate. A lower interest (discount) rate or longer time horizon reduces the capital recovery factor.

Common Energy Efficiency Measures Industrial Sector

- High efficiency motors (especially smaller motors)
- Adjustable speed drives
- Energy management systems for manufacturing processes

The SWEEP study applied the LIEF model to each state in the region, using that state's electricity prices, the electric intensities of each industrial sector, and each sector's current output and projected output growth. For the base case forecast, a 33 percent capital recovery factor was assumed, corresponding to a 15-year average lifetime for efficiency measures and a discount rate of 32 percent. In addition, the base case assumed that 3.25 percent of available cost-effective efficiency measures would be adopted each year. The cost-effectiveness threshold and level of adoption are typical of decision-making in industries where a host of barriers prevent the successful pursuit of energy efficiency measures with paybacks of more than two to three years based on energy savings alone.

In the SWEEP High Efficiency Scenario a lower capital recovery factor and a higher penetration rate were assumed. Specifically, the capital recovery factor was reduced from 33 percent to 9.6 percent while the penetration of efficiency measures was increased from 3.25 to 6.5 percent per year. The lower capital recovery factor (corresponding to a 5 percent discount rate and a 15-year time horizon) and increased penetration rates represent reduced market barriers, fewer capital constraints, and lower transaction costs which are assumed to occur if aggressive policies to promote energy efficiency are pursued in the region.

Summary of Efficiency Potential

Figure 2-1 summarizes the potential energy efficiency savings in 2020 that were used in the development of the Balanced Energy Plan.[2] For each state, savings are highest in the commercial sector, followed by the industrial sector and the residential sector. The savings potential is roughly the same in percentage terms among states in the commercial sector. There is moderate variation in savings potential across the states in the residential and industrial sectors due to differences in climate, industrial mix, and electricity prices.

The efficiency savings in the Balanced Energy Plan represent an aggressive but feasible level of energy efficiency activities throughout the study period. It is based on the assumption that there will be several concerted, long-term, and successful public policies and private sector initiatives to increase the adoption of efficiency measures. Actions necessary to achieve the efficiency savings in the Balanced Energy Plan are discussed in Chapter 4.

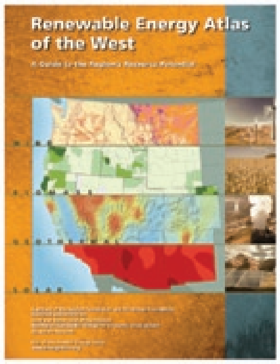
These energy efficiency savings can be achieved cost effectively. The SWEEP study shows that the average cost of the saved energy is approximately 2.0 cents per kilowatt-hour (kWh) in constant year 2000 dollars.[3] These costs include the incremental investments for equipment with greater efficiency plus a 10 percent administration cost to account for the implementation of energy efficiency programs. This cost is less than that for generating, transmitting, and distributing electricity from any type of electricity source.

Fig. 2-1. Energy Savings Potential in 2020

	Region	Arizona	Colorado	Montana	Nevada	New Mexico	Utah	Wyoming
Commercial Sector								
BAU Consumption GWh	140,076	50,835	36,822	5,199	16,696	11,258	15,601	3,666
Savings Potential GWh	49,012	17,836	12,937	1,452	5,751	4,114	5,539	1,383
Savings Potential %	**35.0**	**35.1**	**35.1**	**27.9**	**34.4**	**36.5**	**35.5**	**37.7**
Residential Sector								
BAU Consumption GWh	98,782	38,730	19,858	5,123	14,145	7,486	10,444	2,995
Savings Potential GWh	24,004	10,918	4,176	749	2,898	2,190	2,366	706
Savings Potential %	**24.3**	**28.2**	**21.0**	**14.6**	**20.5**	**29.3**	**22.7**	**23.6**
Industrial Sector								
BAU Consumption GWh	83,082	18,583	14,842	9,013	14,875	6,120	10,735	8,912
Savings Potential GWh	25,253	5,844	4,064	2,414	4,724	2,097	2,956	3,154
Savings Potential %	**30.4**	**31.4**	**27.4**	**26.8**	**31.8**	**34.3**	**27.5**	**35.4**
All Sectors								
BAU Consumption GWh	321,940	108,149	71,523	19,335	45,717	24,864	36,780	15,573
Savings Potential GWh	98,269	34,598	21,177	4,615	13,372	8,401	10,861	5,244
Savings Potential %	**30.5**	**32.0**	**29.6**	**23.9**	**29.3**	**33.8**	**29.5**	**33.7**

Note: Figures rounded to nearest GWh. Rows and columns may not sum due to rounding.

The Potential for Renewable Energy in the Interior West



To assess the potential for renewable energy to help satisfy electricity demands in the region, the Balanced Energy Plan relied on a previous study entitled *Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential*.[4] The Atlas compiled data on the region's wind, solar, biomass and geothermal resources and estimated the potential for electricity generation from these resources.

Wind

Wind power is the fastest-growing energy resource in the world. Today, at the best sites, wind power is cost-competitive with fossil fuel generation. As of January 2004, installed capacity in the seven Interior West states was about 700 megawatts.[5] While wind power has environmental advantages relative to conventional generation of electricity, it must be properly sited to avoid potential land-use conflicts, impacts on birds or other wildlife, and concerns about aesthetic impacts.

The energy potential of wind is expressed by wind power classes ranging from 1 (lowest energy potential) to 7 (highest energy potential). Each class is defined by a range of wind speeds and power densities, defined as the watts per square meter of the area swept by the turbine blades.[6] The wind power potential estimates in the *Renewable Energy Atlas* are based on "windy land area," defined as areas of Class 4 wind potential or greater.[7]

In the estimates developed for the *Renewable Energy Atlas*, areas not suitable for wind power production were screened out. These included land with a slope greater than 20 percent, environmentally sensitive areas (including National Park Service and Fish and Wildlife lands and Forest Service or Bureau of Land Management lands with a special designation), all bodies of water, wetlands, and urban areas.

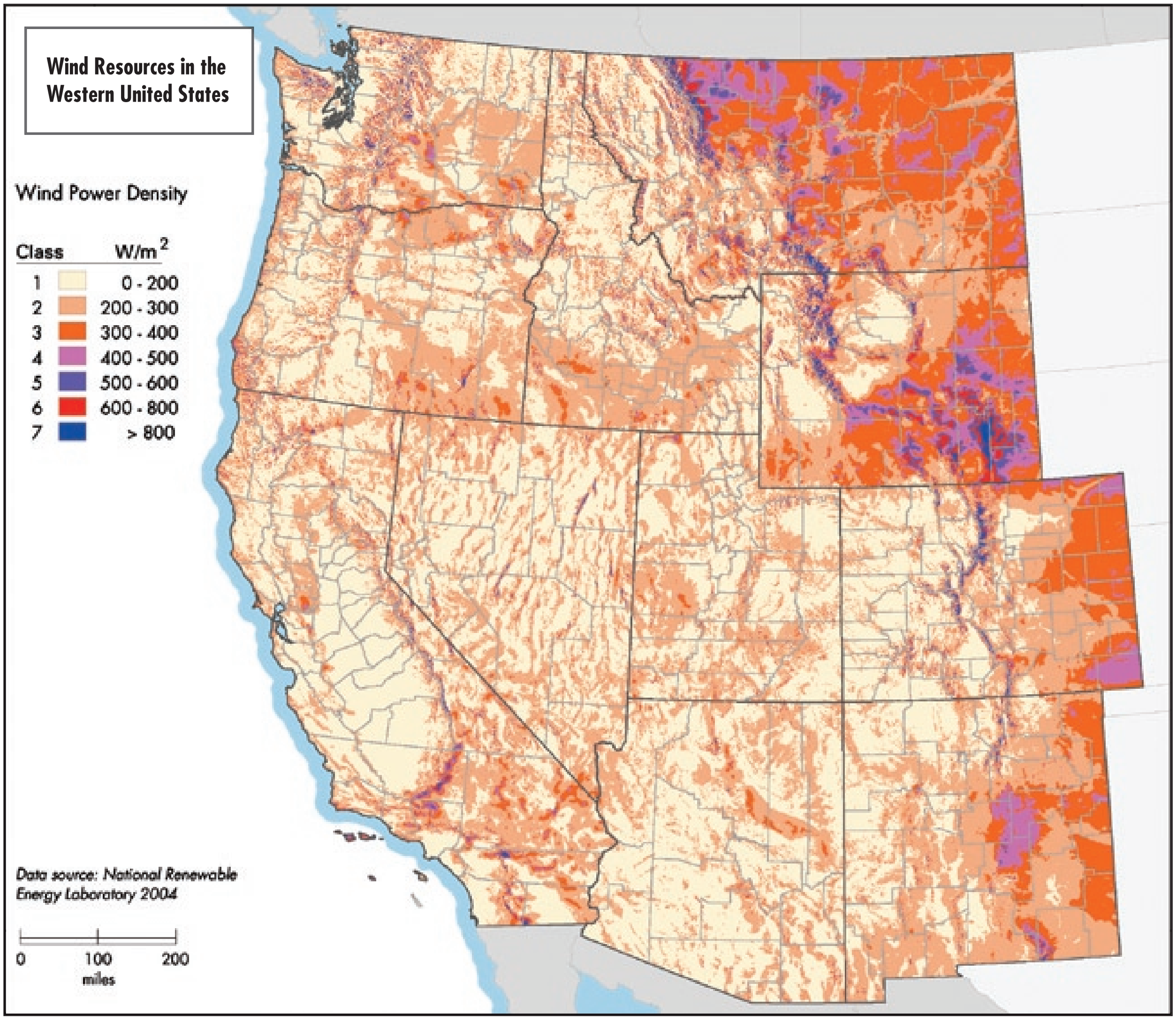
Figure 2-2 shows the wind potential estimates from the Atlas (in gigawatt-hours) by wind class for each state in the Interior West. The resource data used for these estimates were the most recent available for each state in 2002. In 2003 and 2004 updated wind power maps were developed by the National Renewable Energy Laboratory for Arizona, Colorado, Nevada, New Mexico, and Utah. As wind energy mapping techniques have evolved, estimates of windy land area from newer maps have increased. For example, new maps developed for Montana and Wyoming in 2002 increased windy land area estimates in those states by nearly 7 million and 5 million acres respectively. Given this, we believe that the wind energy potential in the Interior West is likely greater than the estimates given in Figure 2-2.

Fig. 2-2. Wind Electricity Production Potential by Class (GWh/yr)

State	Class 4	Class 5	Class 6	Class 7	Total Annual Electricity Potential Class 4-7	Total 2002 Annual Electricity Consumption
Arizona	1,664	2,627	264	0	4,555	62,601
Colorado	510,701	61,087	26,564	2,698	601,050	45,937
Montana	733,804	150,633	86,919	48,686	1,020,042	12,575
Nevada	20,864	17,800	14,517	1,619	54,799	29,204
New Mexico	53,359	1,921	849	154	56,283	19,207
Utah	5,235	3,554	13,722	836	23,348	23,267
Wyoming	422,608	203,410	168,839	87,689	882,547	12,874
Total	**1,748,234**	**441,032**	**311,675**	**141,682**	**2,642,623**	**205,665**

Note: Figures rounded to nearest GWh. Rows and columns may not sum due to rounding.

Source: Land and Water Fund of the Rockies. 2002. *The Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential*; Energy Information Administration. 2003. *Electric Power Annual 2002*. DOE/EIA-0348(2002).



Solar

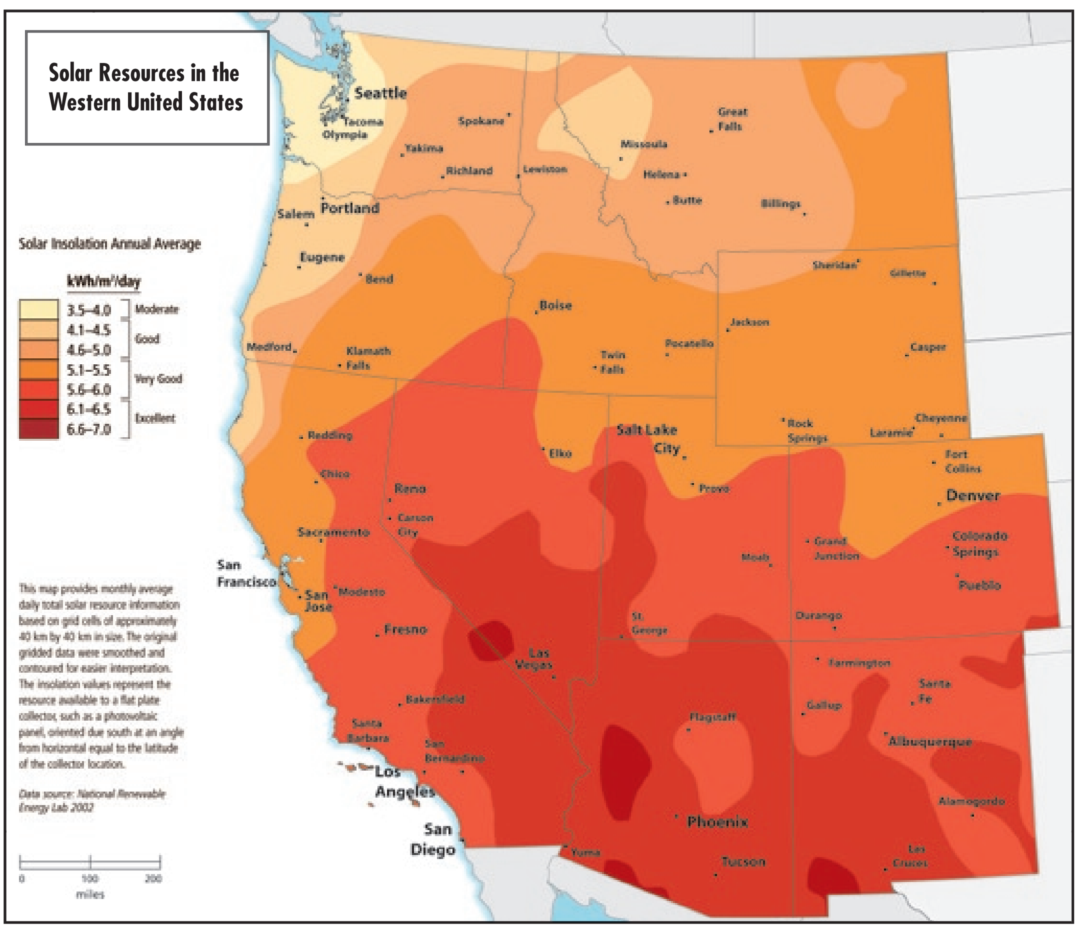
The amount of solar energy that strikes the Interior West each day is enormous. Electricity can be generated from the sun using photovoltaic technologies (which convert sunlight directly into electric energy) or solar thermal technologies (which convert heat from the sun into electric energy). In developing the Balanced Energy Plan we incorporated both photovoltaics and solar thermal technologies.

As a rough estimate of the region's solar energy potential, the *Renewable Energy Atlas* calculated the amount of electricity that would be generated if photovoltaic systems were installed on 0.15 percent of each state's land area. As shown in Figure 2-3, even restricting solar development to this small percentage of total land area yields large generation potentials.[8] As of 2003, installed solar energy capacity in the Interior West was about 10 MW, almost all photovoltaics installed in Arizona.[9]

Fig. 2-3. Solar Electricity Production Potential (GWh/yr)

State	Electricity Production Potential	Total 2002 Annual Electricity Consumption
Arizona	101,000	62,601
Colorado	83,000	45,937
Montana	101,000	12,575
Nevada	93,000	29,204
New Mexico	104,000	19,207
Utah	69,000	23,267
Wyoming	72,000	12,874
Total	**623,000**	**205,665**

Source: Land and Water Fund of the Rockies. 2002. *The Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential;* Energy Information Administration. 2003. *Electric Power Annual 2002.* DOE/EIA-0348(2002).



Geothermal

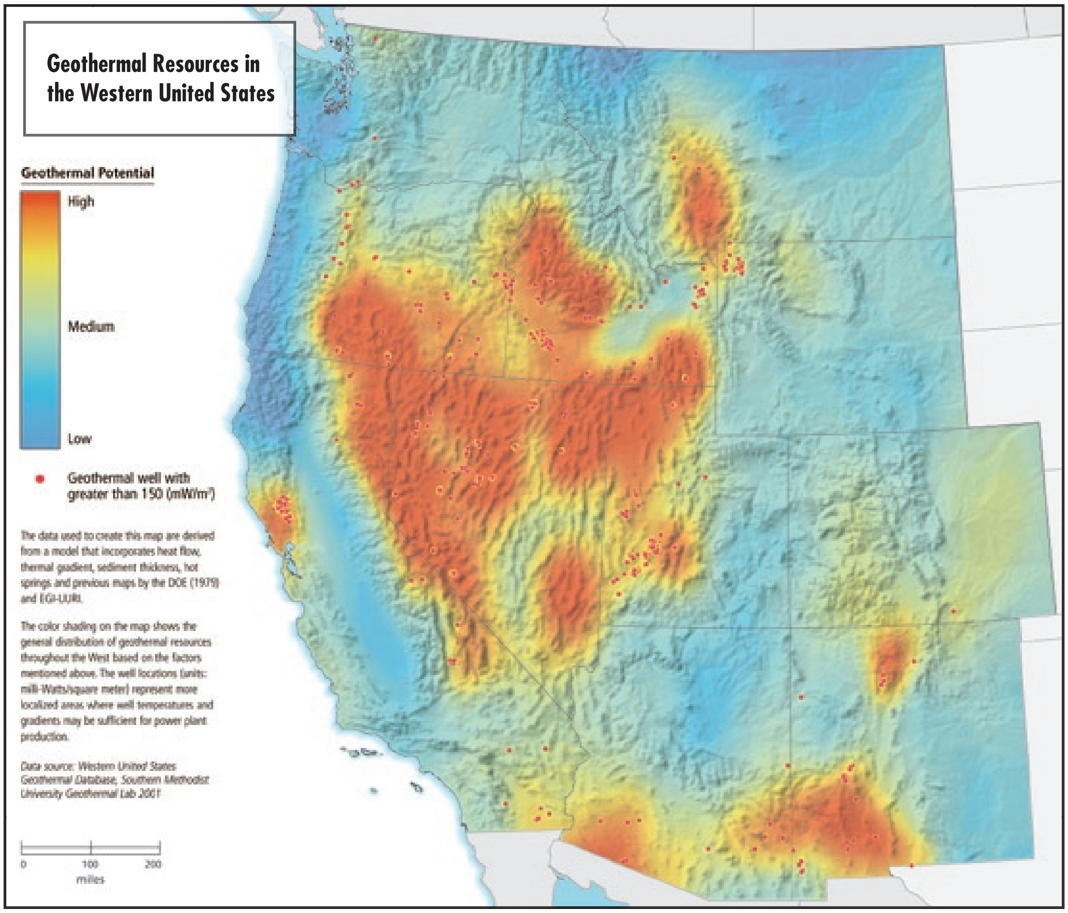
Geothermal energy also has the potential to generate large amounts of electricity in the region. Geothermal power plants use the Earth's heat – in the form of underground steam or hot water – to generate electricity. In the U.S., geothermal resources are found almost exclusively in the West. There are currently about 300 MW of geothermal generating capacity in the Interior West, all located in Nevada and Utah.[10]

The power production estimates included in the *Renewable Energy Atlas* for geothermal energy were taken from the Renewable Fuels Module of the National Energy Modeling System.[11] Those estimates were then screened to include only the more cost-effective resources able to produce electricity for 6 cents per kWh or less.

Fig. 2-4. Geothermal Electricity Production Potential (GWh/yr)

State	Electricity Production Potential	Total 2002 Annual Electricity Consumption
Arizona	5,000	62,601
Colorado	<1,000	45,937
Montana	N/A	12,575
Nevada	20,000	29,204
New Mexico	3,000	19,207
Utah	9,000	23,267
Wyoming	N/A	12,874
Total	**38,000**	**205,665**

Source: Land and Water Fund of the Rockies. 2002. *The Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential*; Energy Information Administration. 2003. *Electric Power Annual 2002*. DOE/EIA-0348(2002).



Biomass

Biomass is a general term for organic materials (agricultural and forest residues, animal waste, and landfill gas) which can be used to produce electricity. In many applications biomass utilizes organic matter that would otherwise be added to landfills or burned without capturing the embodied energy. Biomass electricity can be produced in several ways. Landfill gas is composed primarily of methane and can be used as a power plant fuel much like natural gas. Crop or forest residues can be burned in plants dedicated to biomass fuels or can be co-fired with other fuels such as coal. Although not yet commercialized, a promising option is biomass gasification combined-cycle technology, in which solid biomass fuels are gasified and the gas then burned in a combined-cycle power plant.

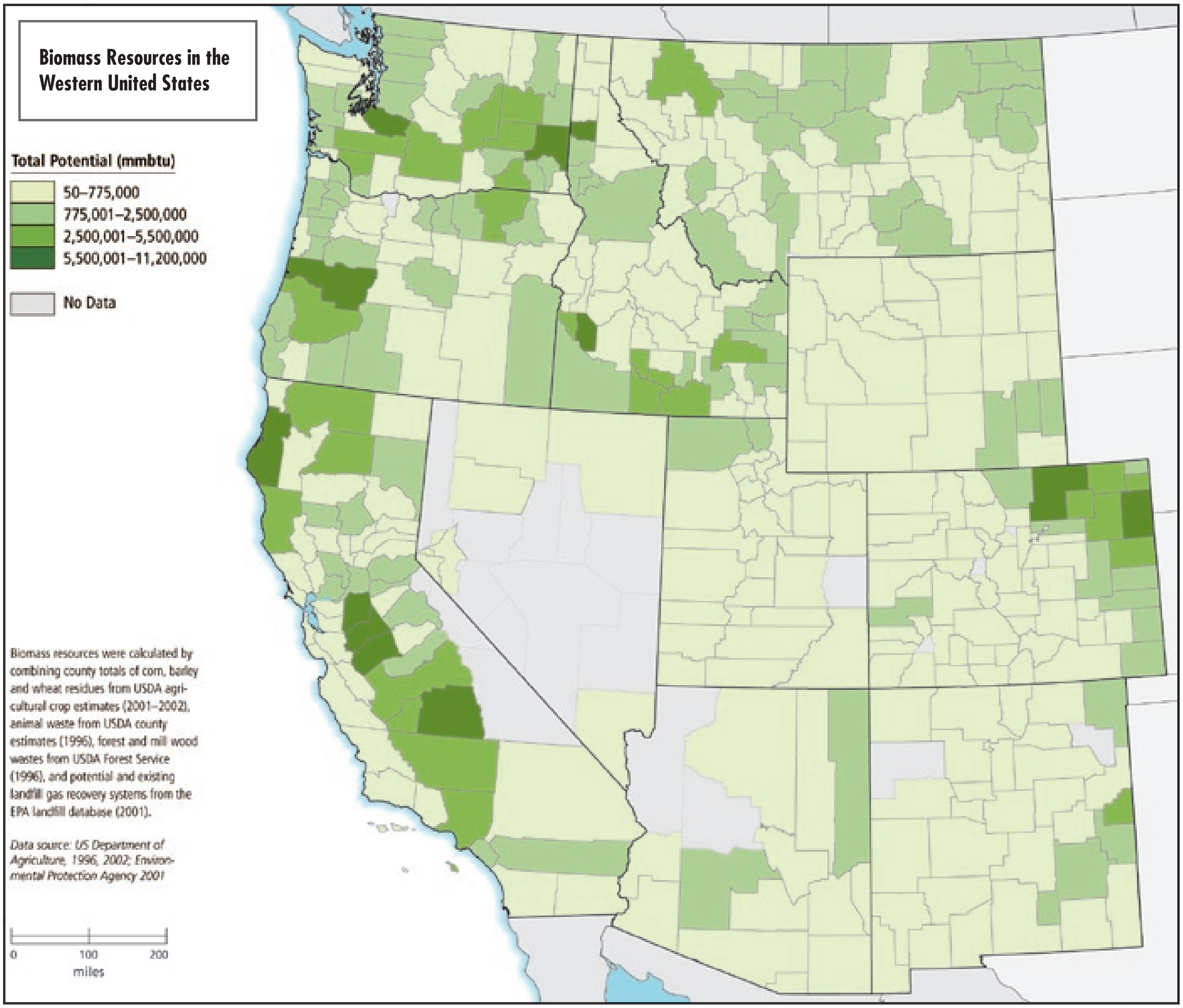


Fig. 2-5. Biomass Electricity Production Potential (GWh/yr)

State	Electricity Production Potential	Total 2002 Annual Electricity Consumption
Arizona	1,000	62,601
Colorado	4,000	45,937
Montana	6,000	12,575
Nevada	1,000	29,204
New Mexico	<1,000	19,207
Utah	1,000	23,267
Wyoming	<1,000	12,874
Total	**15,000**	**205,665**

Source: Land and Water Fund of the Rockies. 2002. *The Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential*; Energy Information Administration. 2003. *Electric Power Annual 2002*. DOE/EIA-0348(2002).

Fast-growing, drought-tolerant "energy crops" may become the biomass fuels of the future. In the West, their development will likely be limited to less arid locales. In the meantime, sustainable forest management, landfills and wastewater treatment facilities can produce biomass for electricity production.

In the *Renewable Energy Atlas*, biomass generation potential was calculated by adding the generation potential for landfill gas, crop residues, forest and mill wood waste, and animal waste. The Atlas estimates do not include the potential from dedicated energy crops. In the seven Interior West states, biomass generating capacity was about 60 MW in 2003.[12]

Summary of Renewable Energy Potential

Figure 2-6 summarizes the region's renewable energy potential, as estimated in the *Renewable Energy Atlas*. Overall, renewable energy has the potential to generate over 16 times the amount of electricity currently consumed in the region. With the exception of wind power, these technologies are still more expensive than conventional fossil fuel generation. Overcoming cost barriers will require continued efforts to commercialize these technologies. In addition, the environmental and risk-diversification benefits of these technologies will need to be more fully included in energy decisions. Chapter 4 discusses some of the key institutional and market barriers facing renewable energy and how they can be overcome.

Fig. 2-6. Potential Electricity Production from Renewable Sources (GWh/yr)

	Wind	Solar	Geothermal	Biomass	Total	Total 2002 Annual Electricity Consumption
Arizona	5,000	101,000	5,000	1,000	112,000	62,601
Colorado	601,000	83,000	<1,000	4,000	689,000	45,937
Montana	1,020,000	101,000	N/A	6,000	1,127,000	12,575
Nevada	55,000	93,000	20,000	1,000	169,000	29,204
New Mexico	56,000	104,000	3,000	<1,000	164,000	19,207
Utah	23,000	69,000	9,000	1,000	102,000	23,267
Wyoming	883,000	72,000	N/A	<1,000	956,000	12,874
Total	**2,643,000**	**623,000**	**38,000**	**15,000**	**3,319,000**	**205,665**

Source: Land and Water Fund of the Rockies. 2002. *The Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential*; Energy Information Administration. 2003. *Electric Power Annual 2002*. DOE/EIA-0348(2002).

The Potential for Combined Heat and Power Resources in the Interior West

Combined heat and power (CHP) projects, also referred to as cogeneration, are facilities that produce both electricity and useful thermal energy, such as steam or hot water, in a single on-site integrated system. This differs from more common practices where electricity is generated at remotely located power plants while on-site boilers and other types of heating and cooling equipment are used to meet thermal energy requirements. Conventional fossil fuel power plants convert only about one-third of the energy in the fuel they burn into electricity, with the rest lost as waste heat. Because CHP facilities use the same fuel to generate electricity and to meet heating or cooling demands, the total efficiency is much greater than producing heat and electrical energy separately. Furthermore, because CHP facilities generate electricity on-site, electricity transmission and distribution losses are avoided.

The greater efficiency of combined heat and power systems provides numerous benefits. With less fuel required to produce the same quantities of electric energy and useful heat relative to traditional technologies, CHP systems can reduce demand for fossil fuels and help take pressure off fossil fuel prices, particularly natural gas. In addition, greater efficiencies mean lower levels of carbon dioxide emissions and, assuming the same levels of pollution controls are installed on CHP systems as would be on centrally located plants, lower levels of other air pollutants.

Combined heat and power has been used for over a century and is an established technology, particularly in industries such as chemical manufacturing, petroleum refining, and paper manufacturing. CHP systems have also been employed in district energy facilities that provide steam and electricity to customers. More recently, the development of

Fig. 2-7. Overview of Combined Heat and Power Technologies

	Microturbine	Reciprocating Engine	Combustion Turbine	Steam Turbine	Fuel Cells
Description	Small electricity generators using high speed rotation. Exhaust heat exchanger transfers thermal energy to hot water system	Diesel or spark ignition engines to generate electricity	Combustion turbine to generate electricity. May be part of a combined-cycle generating unit to increase electricity production	Generate electricity from steam produced in a boiler. Used in medium or large industrial or institutional facilities	Electro-chemical process converting chemical energy of hydrogen into water & electricity. Heat is a byproduct
Typical Electric Generation Capacity	30 kW to 350 kW	50 kW to 5 MW	500 kW to 250 MW	50 MW to over 250 MW	1 to 250 kW
Typical Uses of Heat	Hot water, absorption chillers, dehumidifiers, low pressure steam, direct heat	Hot water, low pressure steam, district heating, absorption chillers	High or low pressure steam, hot water, direct heat, district heating	Low or high pressure steam, district heating	Hot water or steam

Sources: Environmental Protection Agency. *Introduction to CHP Catalogue of Technologies.* http://www.epa.gov/chp/tech_intro.htm; Onsite Sycom Energy Corporation. *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector* and *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, both prepared for the Energy Information Administration. January 2000. Hinrichs, D., R. McGowan, and S. Conbere. Integrated CHP Offers Efficiency Gains to Buildings Market. *Energy User News.* September 27, 2001.

low-cost, high-efficiency reciprocating engines and small natural gas combustion turbines have made CHP systems feasible for smaller manufacturing facilities, universities, hospitals, commercial and government buildings, hotels, and restaurants. Figure 2-7 gives an overview of CHP technologies.

Today, approximately 1800 MW of combined heat and power systems are operating in the Interior West, mostly at industrial facilities. Figure 2-8 shows existing combined heat and power capacity in the region by state.

Fig. 2-8. Existing Combined Heat and Power Generating Capacity

State	Sites	Capacity (MW)
Arizona	21	162
Colorado	19	839
Montana	6	68
Nevada	6	311
New Mexico	18	214
Utah	12	122
Wyoming	9	108
Total	**91**	**1,824**

Source: Energy and Environmental Analysis, Inc. 2004.

To assess the potential for further combined heat and power development in the Interior West, we relied on two studies prepared for the U.S. Department of Energy by Onsite Sycom Energy.[13] State-by-state estimates of the combined heat and power potential at commercial sites in 2000 were taken from the commercial/institutional study. National estimates of combined heat and power potential at industrial sites in 2000 were taken from the industrial study and allocated to states on the basis of the state's share of national electricity consumption by industrial customers. We then scaled up the CHP potential in proportion to the SWEEP baseline growth in commercial or industrial sector consumption over time.[14]

Overall, we estimate that the region has the potential to develop over 15,000 MW of combined heat and power (Figure 2-9).

Fig. 2-9. Potential for Combined Heat and Power in 2020 (MW)

State	Commercial	Industrial	Total
Arizona	2,997	1,378	4,375
Colorado	2,060	475	2,535
Montana	349	743	1,092
Nevada	2,485	846	3,331
New Mexico	607	485	1,092
Utah	972	891	1,863
Wyoming	209	751	960
Total	**9,679**	**5,569**	**15,248**

Source: Onsite Sycom Energy Corporation. 2000. *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector* and *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector*, both prepared for the Energy Information Administration.

Conclusion

The potential for energy efficiency, renewable energy and combined heat and power in the Interior West is significant. In the following chapter we describe how a portion of this potential can be integrated into the region's electricity mix to help meet growing demand in a way that is cost-effective, reduces risk, and

Endnotes

1. Energy Information Administration. 2003. *Annual Energy Outlook 2002.* DOE/EIA-0383(2002). Washington, DC: U.S. Department of Energy.

2. The 2020 savings estimated in the Balanced Energy Plan are slightly lower than those presented in the SWEEP report because the Balanced Energy Plan assumed that the energy efficiency resources would begin being installed one year later than in the SWEEP study.

3. Southwest Energy Efficiency Project. 2002. *The New Mother Lode: The Potential for More Efficiency Electricity Use in the Southwest.* p. 3-13. http://www.swenergy.org/nml/index.html.

4. Land and Water Fund of the Rockies. 2002. *Renewable Energy Atlas of the West: A Guide to the Region's Resource Potential.* http://www.energyatlas.org.

5. American Wind Energy Association. Wind Energy Projects, updated January 21, 2004. http://www.awea.org/projects/index.html. Most of the current wind generation capacity is located in Colorado, New Mexico, and Wyoming.

6.

Wind Power Classes (at 50 meters)		
	Wind Speed (mph)	Wind Power Density (Watts/square meter)
1	<12.5	<200
2	12.5-14.3	200-300
3	14.3-15.7	300-400
4	15.7-16.8	400-500
5	16.8-17.9	500-600
6	17.9-19.7	600-800
7	>19.7	>800

Source: National Renewable Energy Lab

7. Small-scale distributed wind turbines require less wind for economic viability and have been successfully installed in regimes as low as Class 2. Potential energy production from small-scale turbines in lower class regimes is not reflected in these estimates.

8. Potential estimates using other solar technologies such as concentrating photovoltaics technologies or solar thermal technologies would involve a different set of assumptions and yield different estimates. However, regardless of the technology used as the basis for the estimates, the theoretical potential of solar electricity production in the region will be many times the amount of electricity the region consumes.

9. U.S. Department of Energy. Renewable Electric Plant Information System (REPiS 7.0); Cost Evaluation Working Group. *Costs, Benefits, and Impacts of the Arizona Environmental Portfolio Standard.* Arizona Corporation Commission, June 30, 2003; Salt River Project. *Scope and Background Information for Participants in SRP's Sustainable Procurement Principles Development Process.* February 2004; Tucson Electric Power Company. *Demand-Side Management and Renewables Data for Mid-Year 2003* (report to the Arizona Corporation Commission); Arizona Public Service Company. February 25, 2004 press release.

10. U.S. Department of Energy. Renewable Electric Plant Information System (REPiS 7.0); Nevada Division of Minerals. *Nevada Geothermal Update.* June 2003.

11. Of all the renewable resources, geothermal's potential is the most difficult to estimate and the most speculative. This is because geothermal heat lies buried, often at significant depth, and is not easily modeled and verified with available tools. Resource estimates are based mainly on test drilling and 1970s data from the U.S. Geological Survey. Newer geothermal technologies may be able to produce electricity from lower temperature resources, but no comprehensive assessments have been completed.

12. U.S. Department of Energy. Renewable Electric Plant Information System (REPiS 7.0); Salt River Project. *Scope and Background Information for Participants in SRP's Sustainable Procurement Principles Development Process.* February 2004; Tucson Electric Power Company. *Demand-Side Management and Renewables Data for Mid-Year 2003* (report to the Arizona Corporation Commission); Arizona Public Service Company February 25, 2004 press release.

13. Onsite Sycom Energy Corporation. *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector* and *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector.* Both prepared for the Energy Information Administration, U.S. Department of Energy, January 2000.

14. Combined heat and power potential was scaled up relative to baseline growth rather than relative to growth reduced by energy efficiency savings on the simplifying assumption that combined heat and power would be used to meet steam, hot water, or heat needs that would be unaffected by energy efficiency. If energy efficiency reduces the need for electricity from combined heat and power facilities, that excess electricity could be sold into the market or used to displace electricity generated by utilities or independent power producers.

All website references verified May 1, 2004.

Chapter 3 Economic and Technical Basis of the Balanced Energy Plan

Introduction

The previous chapter described the potential for energy efficiency, renewable energy and combined heat and power resources to meet growing electric demands in the Interior West. This chapter demonstrates that these resources can be deployed on a large scale in a Balanced Energy Plan (BEP) to reduce the costs of meeting the demand for electric services, manage the risks of providing electricity, and reduce the environmental impacts and public health liabilities of power production.

Electricity for the Interior West can be supplied under "Business as Usual" (BAU) conditions, that is, under a continuation of past policies and trends. Under BAU the region would continue to rely almost exclusively on fossil fuels to generate electricity.

In the past, Business as Usual has delivered reliable electricity at relatively low rates. However, BAU is becoming increasingly risky, subject to possible higher natural gas prices, drought-reduced hydroelectric generation, and possible costly compliance with future environmental regulations. By offering an alternative vision of the future – one with greater reliance on renewable energy, combined heat and power, and energy efficiency – the Balanced Energy Plan reduces the region's exposure to these risks.

We developed the Balanced Energy Plan as evidence of what could be achieved in the Interior West by 2020. In particular, the BEP stresses:

- Energy efficiency which reduces demand for electricity within the Interior West by about 30 percent by 2020, relative to BAU
- Renewable energy resources which provide about 20 percent of the generation of electricity in the Interior West by 2020
- Combined heat and power which provides about 9 percent of the generation of electricity in the Interior West by 2020

To demonstrate what could be achieved, we addressed various economic and technical issues in meeting the demand for electric energy services under BAU and under the BEP. This chapter presents our analysis of these issues. In particular, we discuss analytical tools, cost assumptions, supply and demand features of BAU and the BEP, and transmission and generation reliability. We then present a summary comparison of the two scenarios and discuss the benefits of the Balanced Energy Plan relative to BAU in terms of cost savings, risk mitigation, and reduced environmental impacts.

Analytical Tools

The system of electricity generation, transmission, and distribution is complex in design and operation. In the western United States, there are hundreds of power plants and thousands of miles of transmission lines to move power from generators to consumers. To develop and evaluate both the Balanced Energy Plan and the BAU case, we used the PROSYM electricity market simulation model as our basic analytical tool. PROSYM takes into account the complexities of the western power grid and allowed us to compare the costs, environmental impacts, transmission requirements, and reliability and risk-mitigation properties of the BEP versus Business as Usual.

PROSYM is a production cost model of the western electric system frequently used by the power industry. The model contains a database of costs and operating characteristics of each existing power plant on the western grid and can be augmented to include cost and operating characteristics of any new power plants added to the system. Subject to transmission and plant operating constraints, PROSYM assumes that plants with lower operating costs will be used (or "dispatched") to meet power demands before plants with higher operating costs are dispatched. Thus, for a given set of generating resources and transmission capabilities, the cost of operating the system is minimized. The entire western grid (eleven western states and parts of western Canada and Baja California) is included in the model, enabling an integrated analysis of how the entire system operates. PROSYM divides the western electric grid into a number of interlinked transmission areas, designed to capture the transmission capabilities between sub-regions in the West. In our analysis, there are 10 distinct transmission areas in the seven-state study region and 22 within the entire western grid.

Fuel Price and Generation Cost Assumptions

An evaluation of any future scenario for meeting electricity demands requires assumptions about how energy production, delivery, and consumption systems work. The following section presents some key assumptions pertaining to fuel costs and to capital and total electricity production costs of new generating facilities. More detail can be found in Appendix A.

Fuel prices greatly influence the cost of meeting the demand for electric energy services. To project future coal prices, we applied percentage changes in prices as forecast in the *Annual Energy Outlook 2002* to 2002 costs at individual plants. For natural gas we took 2002 delivered gas prices from the PROSYM database and adjusted them using forecast growth rates for natural gas prices from the *Annual Energy Outlook 2003*.

The principal fossil fuel used to generate electricity in the Interior West is coal, and our analyis assumes that the price of coal will decline slightly in constant dollars over the study period (Figure 3-1). By contrast, natural gas prices are assumed to rise over the study period, ending up in 2020 at around $5 per million BTUs in year 2000 dollars. These prices are lower than the $5 to $6 per million BTUs the region is currently experiencing, and dramatically lower than the $9 to $10 price spikes that have occurred within the last three years. If gas prices remain high, then the economic benefits of the Balanced Energy Plan will be greater than presented in this report.

With regard to generation resources, Figure 3-2 summarizes capital costs and levelized costs per kWh of a generator installed in the year indicated.[1] These cost assumptions are based on the *Annual Energy Outlook 2002*. However, we used other information where better data were available, such as photovoltaic costs from Tucson Electric Power Company. Costs presented in the table and used in the analysis exclude incentives such as the federal production tax credit for wind energy generation. Note that capital costs of most major technologies are assumed to decline over time in constant dollars. Thus, as new generation facilities are added over time, the additions are assumed to incorporate technological improvements.

Fig. 3-1. Fossil Fuel Price Assumptions for the Interior West

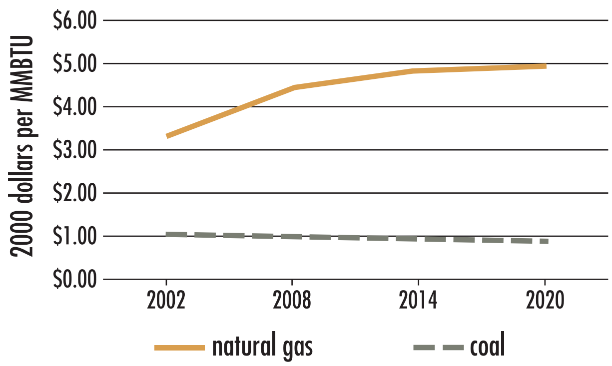


Fig. 3-2. Cost and Performance Assumptions for New Generating Facilities (costs in 2000 dollars)

	Coal	Natural Gas			Wind †	Geothermal	Solar			Biomass		
	Pulverized Coal	Combined Cycle	Combustion Turbine	CHP *			PV Central Station	PV Rooftop	Solar Thermal	Landfill Gas	Combined Cycle	Co-firing ‡
Typical MW	400	250	100	50	150	50	1	0.002	50	5	100	400
Overnight capital cost:												
2008 ($/kW)	1,110	453	336	730	924	2,340	5,400	9,177	5,400	1,399	–	–
2014 ($/kW)	1,083	448	333	730	909	2,259	4,770	7,504	4,770	1,399	–	200
2020 ($/kW)	1,068	443	329	730	870	2,171	4,550	5,302	4,550	1,399	1,569	200
Levelized cost:												
2008 (cents/kWh)	4.36	5.02	6.24	4.58	4.24	5.23	26.28	66.58	24.15	4.58	–	–
2014 (cents/kWh)	4.30	5.20	6.41	4.76	4.18	5.08	23.26	54.55	21.50	4.58	–	2.10
2020 (cents/kWh)	4.25	5.27	6.47	4.83	4.04	4.92	22.20	38.71	20.58	4.58	7.03	2.08

Dash indicates new units not deployed in time period indicated.

* Costs for CHP units are incremental costs of adding electric generation to steam or hot water production.

† Wind costs do not include federal production tax credit.

‡ Capital cost pertains to adding co-firing capability to existing coal units. Co-firing data pertain to specific existing plants in Colorado and Montana, some of which have very low coal costs.

The Power Sector in the Interior West under Business as Usual Conditions

Electricity Demand under BAU

The BAU electricity demands in the Interior West used in this study are consistent with the BAU forecasts used in the SWEEP *New Mother Lode* study, extended to include Montana.[2] The forecasts used in the SWEEP study took account of residential, commercial and industrial sector growth in each state as well as future changes in the electricity intensity of each sector as projected in the *Annual Energy Outlook 2002*. These BAU forecasts assume continuation of existing modest energy efficiency programs and trends.

Figure 3-3 shows total BAU electricity demands by state from 2002 to 2020 (measured in gigawatt-hours). Under BAU conditions, electricity demand in the Interior West is expected to increase annually by 2.4 percent on average during the period. By 2020, demand is expected to be roughly 322,000 GWh, an increase of over 54 percent relative to 2002. Arizona and Colorado are the two largest consumers of electricity, accounting for over half the electricity demand throughout the study period. Arizona has the highest growth rate, Wyoming the lowest.

Electricity demand varies from hour to hour and typically exhibits a seasonal peak. Figure 3-4 shows projected peak demand by state from 2002 through 2020 under Business as Usual. Because these peak demands occur at different times in different states, they should be interpreted as noncoincident peaks. The noncoincident peak demand in the Interior West is projected to increase at an annual compound growth rate of 2.6 percent from 2002 through 2020. The highest peak demands occur in Arizona and Colorado.

Fig. 3-3. Load Growth: Business as Usual

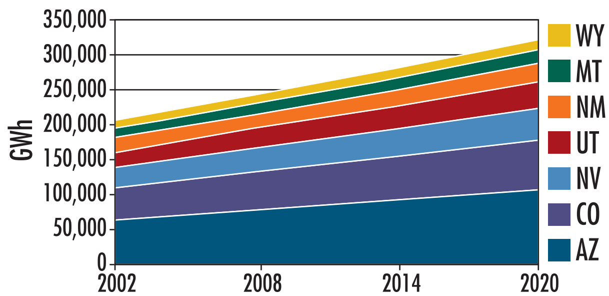
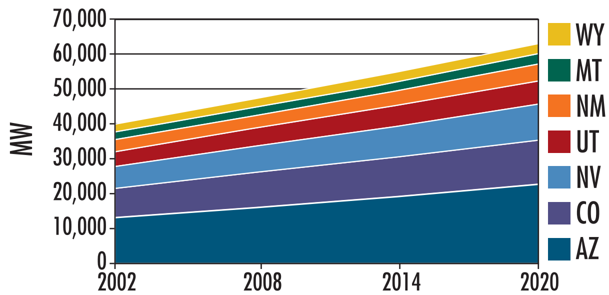


Fig. 3-4. Noncoincident Peak Demand: Business as Usual



Electric Capacity Additions under BAU

Under BAU conditions, new power plants will be added to meet growing electricity demand in the Interior West, to generate power for export to California and the Pacific Northwest, and to replace power plants that are retired during the study period. Some new power plants are well on their way to being constructed, and these are termed "planned" units. Planned units alone are not sufficient to meet growing electricity needs and maintain a reliable electrical system throughout the study period, so "unplanned" units were also included in the analysis.

Planned Generating Units

We defined planned units as those that were under construction in 2002 and scheduled to be on-line by the summer of 2005. The analysis added these units to the power system first and placed them in the appropriate state and transmission area, based on the known locations of the units. We used the PROSYM database as our source for identifying and locating planned fossil fuel units. For planned renewable energy facilities we supplemented information from the PROSYM database with data from the California Energy Commission and the American Wind Energy Association. Figure 3-5 shows that nearly all planned generation in the Interior West through 2005 is natural gas combined-cycle and combustion turbine technology, with the majority of the new planned units being built in Arizona and Nevada.

Unplanned Generating Units

Once the planned units were in place, unplanned units necessary to meet future electricity demands and maintain reliability were added. As a starting point for determining the mix of unplanned generators, we reviewed forecasts of new unplanned units from the *Annual Energy Outlook 2002* (AEO) for the 2003-2020 period. The AEO forecasts are based on an economic analysis of the capital and production costs and technical characteristics of various types of power plants to determine the most likely mix of new plants over time. In addition, we reviewed proposals for plants currently under consideration by utilities and other power developers for development in the period beyond 2005. Most of these longer range proposals are for

Fig. 3-5. Business as Usual Planned Generating Capacity Additions by 2005 (MW)

Resource Type	Arizona	Colorado	Montana	Nevada	New Mexico	Utah	Wyoming	Total
Natural Gas Combined Cycle	5,985	515	230	2,735	750	0	0	10,215
Natural Gas Combustion Turbine	185	190	0	0	40	125	20	560
CHP	0	0	0	150	0	0	0	150
Wind	0	160	40	0	205	0	0	405
Total	**6,170**	**870**	**275**	**2,880**	**990**	**125**	**20**	**11,330**

Note: Figures rounded to nearest 5 MW. Rows and columns may not sum due to rounding.

coal-fired generation. We identified roughly 30 proposed coal plants representing about 25,000 MW of generating capacity. Of this proposed capacity, we identified 10,000 MW that were being proposed by economically viable developers and were currently moving through the permitting process. This amount of coal-fired generation is consistent with AEO 2002 forecasts.

Three states in our region have renewable energy standards, which are governmental requirements that a portion of the electricity sold in the state must come from renewable resources. For these states, we assumed that the standards would be met as part of the BAU scenario.

To determine where to locate unplanned units, we considered several factors depending on resource type. Natural gas plants were located near population centers where power is most needed. Coal plant sites were determined primarily based on locations for new coal plants currently proposed by developers. Because the renewable portfolio standards that drive most of the renewable capacity additions in the BAU case encourage or require the capacity to be located in-state, the majority of the renewable resources are located in states where portfolio standards exist.

In developing the BAU case we also assumed that existing coal plants will be retired after 60 years of service and that gas-fired steam plants will be retired after 55 years of service. These service lifetimes are consistent with utility expectations. As a result, regionwide, 2595 MW of coal and gas plants are retired under BAU conditions. Of these retirements, 635 MW are coal plants and 1960 MW are natural gas steam plants.

Figure 3-6 shows capacity added and retired under BAU by 2020. Under BAU conditions we estimate that 27,790 MW of new generating capacity will be added to the region by 2020 while 2610 MW are retired. Of the capacity additions, we estimate that 58 percent will be gas-fired, 36 percent coal-fired and 6 percent renewable energy technologies. Figure 3-7 shows the geographic distribution of net capacity additions under the BAU scenario.

Current Renewable Energy Standards in the Interior West

Nevada – 15 percent of retail electricity sales must come from renewable energy systems by 2013, with at least 5 percent of the standard met by solar resources.

New Mexico – 10 percent of retail electricity sales must be derived from renewable resources by 2011.

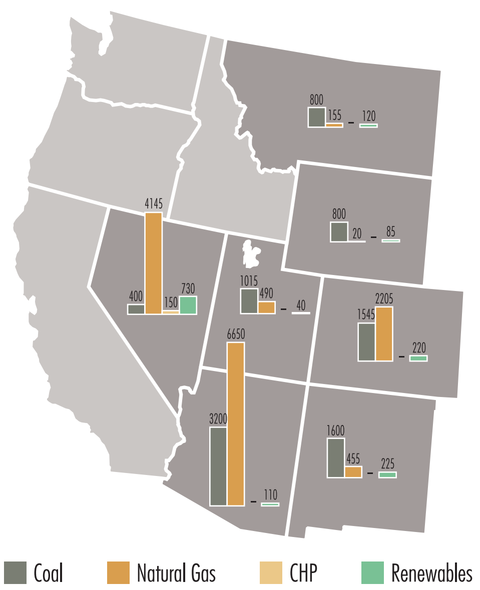
Arizona – 1.1 percent of retail sales must be derived from renewable resources by 2007, with at least 60 percent of the standard met by solar resources.

Fig. 3-6. Business as Usual Capacity Additions and Retirements by 2020 (MW)

Technology	Additions	Retirements	Net Additions	Additions as Percent of Total
Coal	10,000	-635	9,365	36.0%
Natural Gas	16,075	-1,960	14,115	57.8%
CHP	150	0	150	0.5%
Hydro	0	-5	-5	0.0%
Nuclear	0	0	0	0.0%
Renewables	1,530	0	1,530	5.5%
Other	35	-10	25	0.1%
Total	**27,790**	**-2,610**	**25,180**	**100%**

Note: Figures rounded to nearest 5 MW. Rows and columns may not sum due to rounding.

Fig. 3-7. Net Capacity Additions by 2020: Business as Usual



Note: Figures rounded to nearest 5 MW.

Source: Brad Bartlett

San Juan coal-fired generating plant, New Mexico

The Power Sector in the Interior West under the Balanced Energy Plan

Like the Business as Usual case, the Balanced Energy Plan must be able to reliably meet the demand for electric services in the Interior West, generate power for export to California and the Pacific Northwest, and replace any power plants that are retired during the study period. However, in contrast to BAU, which relies almost exclusively on new conventional coal and natural gas power plants to fulfill unmet requirements, the Balanced Energy Plan relies primarily on energy efficiency, renewable energy, and combined heat and power resources.

The Role of Energy Efficiency in the Balanced Energy Plan

Energy efficiency is at the core of the Balanced Energy Plan. In the BEP, the cost-effective efficiency measures identified in the SWEEP report are adopted. As a result, between 2002 and 2020 electricity demand in the Interior West grows at roughly 0.4 percent per year, compared to 2.4 percent growth under Business as Usual. Peak load growth is also lower, growing at 0.5 percent per year compared to 2.6 percent per year under BAU. For the region as a whole, by 2020, the BEP results in electricity demand and peak load requirements that are 31 percent below BAU levels. Figures 3-8 and 3-9 show state-by-state growth in electricity loads and peak demands under the BEP, while Figure 3-10 shows electricity demand under the BEP relative to BAU for the seven-state region as a whole.

Assumptions concerning the costs of obtaining the energy savings are from the SWEEP study. When averaged across the region and over the study period, energy efficiency measures cost about 2.0 cents per kWh saved in constant

Fig. 3-8. Load Growth: Balanced Energy Plan

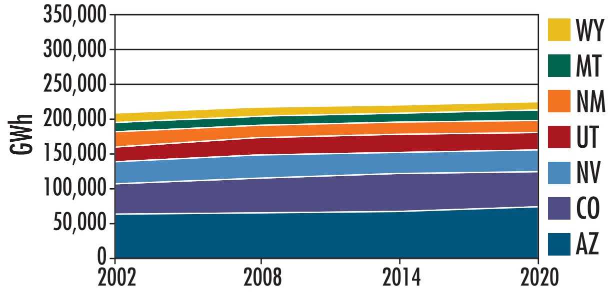


Fig. 3-9. Noncoincident Peak Demand: Balanced Energy Plan

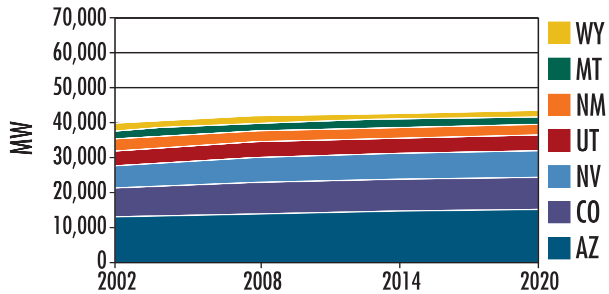
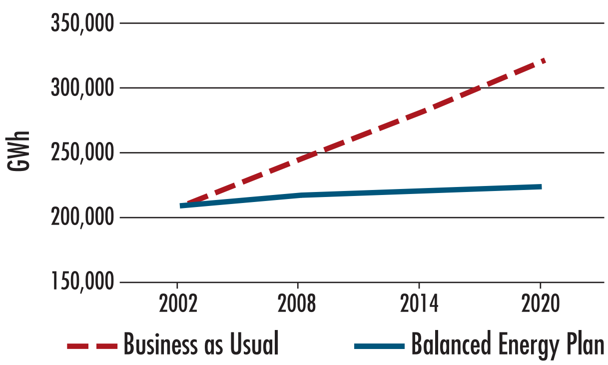


Fig. 3-10. Electric Load Growth in the Interior West: Business as Usual & Balanced Energy Plan



year 2000 dollars.[3] These costs refer to the annualized incremental investments in equipment with greater efficiency plus a 10 percent administration cost to account for the implementation of energy efficiency programs.

Renewable Energy Capacity Additions in the Balanced Energy Plan

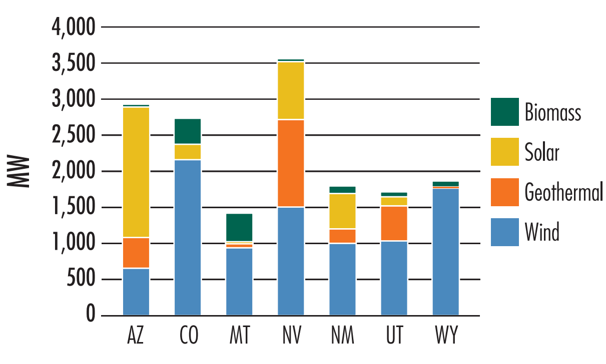
The Balanced Energy Plan adds 15,410 MW of renewable energy capacity to the region's electric resource base. While this is roughly 10 times the amount of renewable capacity added under BAU, it still represents a small fraction of the region's renewable energy potential. Figure 3-11 shows the amounts and types of renewable energy generation added under the BEP.[4] Figure 3-12 shows the geographic distribution of renewable generation in 2020.

Fig. 3-11. Balanced Energy Plan Additions to Renewable Energy Generating Capacity (MW)

Technology	2003–2008	2009–2014	2015–2020	Total
Wind	3,215	2,810	2,805	8,835
Geothermal	960	925	200	2,085
Solar	885	1,005	1,585	3,480
Biomass	115	475	425	1,015
Total	**5,175**	**5,220**	**5,020**	**15,410**

Note: Figures rounded to nearest 5 MW. Rows and columns may not sum due to rounding.

Fig. 3-12. Renewable Energy Generating Capacity in 2020: Balanced Energy Plan



To develop the level and mix of renewable energy resources added, we reviewed the potential for renewables as described in Chapter 2 and estimated the costs of each type of technology. We limited the total amount of renewable energy so that the cost premium across all renewable technologies above conventional generation cost was between 1 and 2 cents per kWh, and we sought diversity among resources. This led to approximately 20 percent of the region's electric mix coming from renewables by 2020.

Locations of Renewable Energy Capacity

To determine locations for developing renewable energy generating capacity, we considered each renewable technology separately. We assumed that geothermal facilities would be located where the potential is highest, using information from the Southern Methodist University Geothermal Lab's *Western United States Geothermal Database* and the Department of Energy National Energy Modeling System for 51 geothermal sites. The highest geothermal potentials are found in Nevada and Utah, with some potential in Arizona, New Mexico, and Montana. Biomass potential is greatest where agricultural and forestry activities occur and in metropolitan areas where large landfills can be used as energy resources. The greatest biomass potential in the Interior West is located in Colorado and Montana. Solar energy potential is greatest in Arizona, southern Nevada, and southern New Mexico.

Good wind sites are available in all of the states in the region but are especially prevalent in Wyoming, Montana and Colorado. In evaluating where to locate wind capacity, we analyzed two cases. In the first case, only the highest quality wind sites (Class 6 and 7) were assumed to be developed. These sites are located primarily in Wyoming and Montana. While these sites have outstanding wind resources, they also are remotely located from load centers and generally incur greater transmission costs. We referred to this case as the "remote wind" case.

In the second case we located some of the wind resources closer to load centers. This lowered transmission costs but required tapping lower quality, higher cost Class 4 and 5 wind sites. We referred to this case as the "near wind" scenario. We found that the higher production costs of the near case were roughly offset by the higher transmission costs of the remote case and that overall the two cases were nearly equal in cost. However, we concluded that the near case offered several advantages:

- A more dispersed geographic distribution of resources and associated economic development impacts
- Less need for major interstate transmission upgrades and the associated challenges of regionwide transmission planning and financing
- Dispersion of resources, which reduces the impact of localized failures of supply and transmission
- Diversity of resources to take advantage of differences in weather patterns so that wind energy generation is not as susceptible to correlated changes in wind patterns

Given this, we chose to base the wind locations in the Balanced Energy Plan on the near case, with some modifications. These involved moving some of the wind capacity from lower quality sites in Colorado to higher quality sites in Wyoming. The amount of capacity shifted required modest additional interstate transmission upgrades, but it allowed tapping wind resources with lower production costs. Overall, the modifications decreased the costs of the plan.

Combined Heat and Power in the Balanced Energy Plan

The Balanced Energy Plan adds 3135 MW of combined heat and power resources to the region (Figure 3-13). To determine the amount added, we started with the CHP potential described in Chapter 2 for each state. We then assumed that 1.5 percent of that potential would be installed in each year in the study except in the first year, where we assumed that only 0.75 percent would be installed. By 2020 this results in about 20 percent of the region's combined heat and power potential being developed.

Fig. 3-13. Balanced Energy Plan Additions to CHP Capacity (MW)

State	2003-2008	2009-2014	2015-2020	Total
Arizona	230	315	260	805
Colorado	150	215	160	520
Montana	35	100	85	220
Nevada	315	260	190	765
New Mexico	65	110	65	235
Utah	130	115	125	370
Wyoming	45	85	80	210
Total	**965**	**1,205**	**965**	**3,135**

Note: Figures rounded to nearest 5 MW. Rows and columns may not sum due to rounding.

Fig. 3-14. Balanced Energy Plan Capacity Additions and Retirements by 2020 (MW)

Technology	Additions	Retirements	Net Additions	Additions as Percent of Total
Coal	0	-4,810	-4,810	0.0%
Natural Gas	7,815	-3,240	4,575	29.6%
CHP	3,135	0	3,135	11.9%
Hydro	0	-5	-5	0.0%
Nuclear	0	0	0	0.0%
Renewable Energy	15,410	0	15,410	58.4%
Other	35	-10	25	0.1%
Total	**26,400**	**-8,060**	**18,335**	**100%**

Note: Figures rounded to nearest 5 MW. Rows and columns may not sum due to rounding.

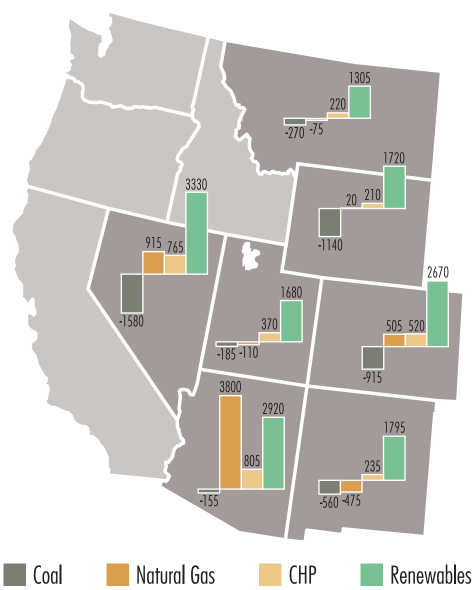
Conventional Fossil Fuel Capacity in the Balanced Energy Plan

While the Balanced Energy Plan relies heavily on efficiency, renewables, and CHP resources, the plan does include 7815 MW of new conventional natural gas-fired capacity that was already under construction as of 2002 and scheduled to be on-line by the summer of 2004. No new coal plants are added under the Balanced Energy Plan.

Like the BAU case, the Balanced Energy Plan retires 2595 MW of existing coal and natural gas plants that reach 60 and 55 years of age respectively during the study period. In addition, the BEP includes early retirement of another 5455 MW of the region's less efficient and most polluting fossil fuel plants. These plants are not needed in the BEP, as a result of the significantly lower load growth and the additional renewable and CHP resources.

Figure 3-14 shows the capacity additions and retirements under the Balanced Energy Plan by 2020. Of the capacity added, 30 percent is conventional natural gas, 12 percent is combined heat and power, and 58 percent is renewable energy. Although the Balanced Energy Plan includes no new nuclear or hydroelectric power plants, like the BAU scenario it does assume the continued operation of the region's one nuclear power plant (the Palo Verde plant in Arizona) and nearly all of the region's existing hydroelectric capacity. The state-by-state distribution of net capacity additions under the BEP is shown in Figure 3-15.

Fig. 3-15. Net Capacity Additions by 2020: Balanced Energy Plan



Note: Figures rounded to nearest 5 MW.

Ensuring a Reliable Power System

In developing both the BAU scenario and Balanced Energy Plan we had to ensure that there were adequate generation and transmission resources available to meet power needs in all parts of the region during all times of the year. This section describes how the PROSYM model was used to ensure that the generation and transmission resources in both scenarios constitute a reliable power system.

Generation Reliability

There are many factors which affect generation system reliability, including forced and scheduled power plant outage rates, variations in demand (especially peak demand) and total generating capacity.

Utilities use several measures of reliability to provide insight into the ability of generation systems to deliver energy to meet consumer demands. The PROSYM model estimates "energy not served," which is the statistical expected value of kilowatt-hours of demand during the year which exceeds supply, given the probabilities of outages and demand variations and given the set of generating resources with their performance characteristics. Under Business as Usual and under the Balanced Energy Plan, PROSYM estimates that energy not served is zero for the entire western United States. We therefore conclude that both cases provide adequate reliability.

In the Balanced Energy Plan we paid special attention to the effect of intermittency of wind resources on system reliability. Wind energy is intermittent in the sense that the ability to generate electricity depends on whether the wind is blowing. Therefore, wind generators must be accompanied by sufficient generating capacity within the generation system – including conventional power plants and other renewable energy generators with different operating patterns – to meet customer demand at all times.

PROSYM allows for a sophisticated assessment of forced power plant outages, which can be used to model intermittent renewable resources. Forced outages are modeled assuming that they will occur on a random basis. To incorporate the effects of intermittency, we represented wind generation by using an outage rate that is 100 percent minus the wind generation capacity factor. The outage rates were broken down seasonally based on data from ten wind monitoring stations throughout the Interior West. We also modeled each wind generator as a series of capacity steps to reflect variations in wind speed and hence variations in power production. As a result of these modeling assumptions we were able to represent variations in intermittent wind generation within the western grid and to reflect the costs of incorporating intermittent generation.[5]

In the Balanced Energy Plan, we developed a system of intermittent and other renewable resources and conventional resources with sufficient capacity and adequate availability to meet customer demand in all hours of the year, for each year studied.

System reliability also depends on the locations of power plants, especially those needed to serve peak demand when there are transmission import limitations affecting large load centers. As noted earlier, natural gas plants were assumed to be located near load centers. Combined heat and power and rooftop photovoltaic projects in the Balanced Energy Plan are located within load centers. And, as noted above, we located renewable energy projects throughout the region and did not just concentrate them in a few states. In addition, energy efficiency in the Balanced Energy Plan reduces peak demand, thereby relieving transmission congestion. Thus, the BEP should work to improve reliability with respect to transmission import limitations at system peaks.

Transmission Reliability

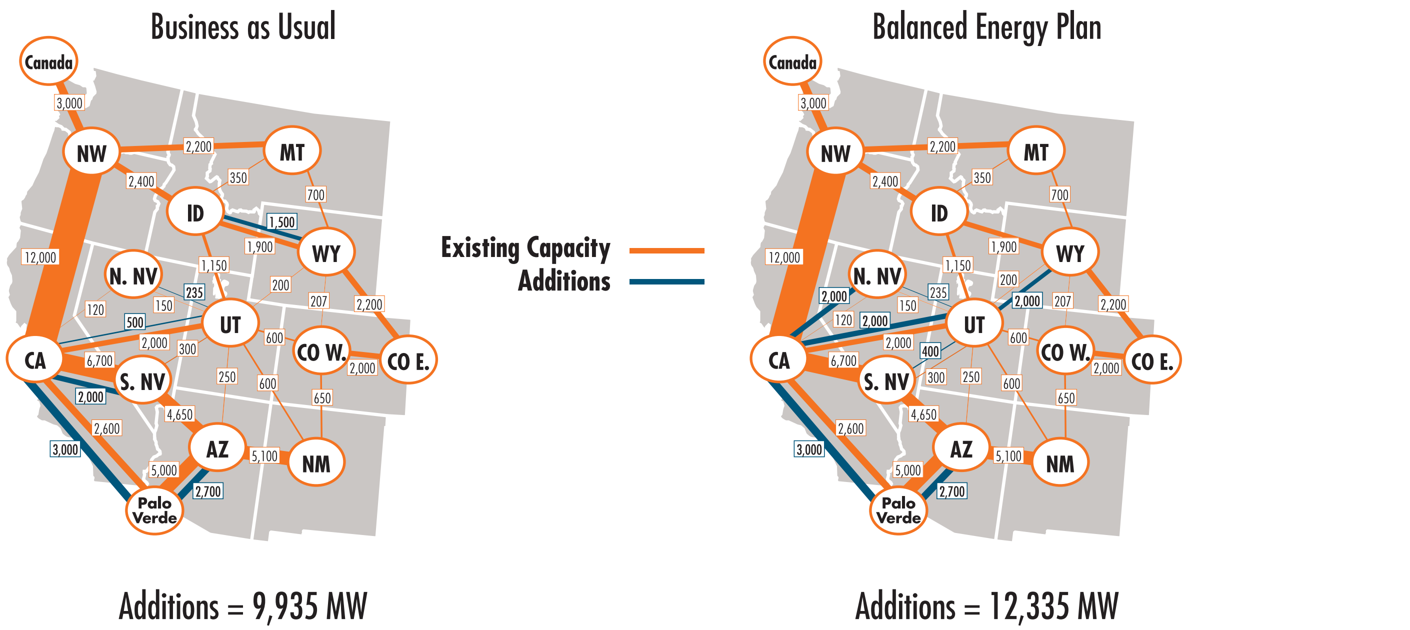
In our assumptions about siting new conventional and renewable energy power plants, we had to ensure adequate transmission capacity to reliably deliver electricity to consumers in the Interior West, California, the Pacific Northwest, and parts of western Canada and Baja California. We broke transmission down into inter-area flows and intra-area flows, using 10 transmission areas within the Interior West and 22 within the entire western grid, as defined within PROSYM.

We undertook several analyses of transmission and distribution system needs. First, we assumed that capacity upgrades would be needed as demand increases, but we did not have sufficient detail to look at specific transmission lines or distribution systems. Instead, we developed average costs of transmission and distribution capacity per kilowatt-hour of load. These costs were determined by analyzing the transmission and distribution cost information in the Department of Energy's National Energy Modeling System using *Annual Energy Outlook 2002* assumptions. In the Balanced Energy Plan, where load growth is reduced, some transmission and distribution upgrades are avoided.

Because our analyses deviate from the assumptions in the National Energy Modeling System with regard to the location, timing, amount and type of generating capacity installed, we also looked for cases where inter-area transmission capacities might be inadequate. We could not model transmission loadings in great detail, so we developed a rule of thumb to determine when new transmission capacity between transmission areas would be needed in future years. The PROSYM model provides information about transmission capacities and loadings between transmission areas in the West. For future years, we applied a rule of thumb that if a path between transmission areas was loaded to at least 50 percent of its capacity for at least 75 percent of the time, an upgrade would be needed. We reviewed recent transmission loadings in the West and found that transmission paths meeting our rule of thumb had load factors of 65 percent or greater. Thus, we added transmission capacity between transmission areas when paths exhibited average load factors above 65 percent.[6]

We found that the Balanced Energy Plan required more inter-transmission area upgrades than Business as Usual, due to the need to move power from remotely located renewable resources to population centers. Figure 3-16 shows the inter-transmission area upgrades needed for each scenario.

Fig. 3-16. Inter-Transmission Area Upgrades: Business as Usual and the Balanced Energy Plan



For wind resources we assumed that additional upgrades would be required within transmission areas both to connect wind farms to the nearest point on the grid and to move wind-generated electricity to load centers within transmission areas or to the edge of transmission areas where it can be exported to other parts of the region. More detail on the assumptions and analyses used to determine transmission needs and costs can be found in Appendix B.

Summary Comparison of the Balanced Energy Plan and BAU

Figure 3-17 summarizes electricity consumption and generation in the Interior West under the Balanced Energy Plan and under Business as Usual. We start with the same baseline forecast of consumption for both the BEP and BAU (line 1). To this we add net electricity exports from the Interior West (line 2).[7] Note that net exports are smaller in the BEP because we assume importing regions (California and the Pacific Northwest) pursue their own energy efficiency measures in tandem with the Interior West; therefore these importing states demand less electricity. To calculate total demand, we subtract energy efficiency savings from baseline consumption adjusted for net exports (lines 3 and 4). Energy efficiency savings in the BAU case are zero (line 3) because the savings are built into the baseline consumption. With regard to generation, the Balanced Energy Plan makes far greater use of renewable resources and combined heat and power and less use of conventional resources than BAU (lines 5, 6 and 7). Total generation equals total demand.

Fig. 3-17. Interior West Electricity Consumption and Generation (GWh)

Component	2002	Business as Usual 2020	Balanced Plan 2020
1. Baseline consumption in the Interior West	208,520	321,940	321,940
2. Net exports from the Interior West	85,346	113,665	99,213
3. Energy efficiency savings in the Interior West	0	0	98,269
4. Total demand (= 1+2-3)	**293,866**	**435,604**	**322,884**
5. Generation from conventional resources	285,136	420,490	228,245
6. CHP generation	5,260	3,525	28,303
7. Generation from non-hydro renewable resources	3,470	11,589	66,336
8. Total generation (= 5+6+7 = 4)	**293,866**	**435,604**	**322,884**

Transmission and distribution losses are included with consumption and exports. BAU energy efficiency savings are built into baseline consumption.
Note: Figures rounded to nearest GWh. Columns may not sum due to rounding.

Source: Joel Renner/INEEL

Steamboat Hills geothermal plant, Nevada

The generation mix by resource type for the Business as Usual case and the Balanced Energy Plan are shown in Figures 3-18 through 3-21. Total generation is less under the BEP because of the increased role of energy efficiency throughout the West. Coal generation increases under BAU but decreases under the Balanced Energy Plan. Natural gas generation (including CHP) increases under both scenarios, but it increases more slowly under the Balanced Energy Plan. By 2020, natural gas consumption for power generation under the BEP is only about half that under BAU. This decreased consumption occurs because older, less efficient plants are retired under the Balanced Energy Plan and because new gas generation is more fuel efficient, especially combined heat and power. Natural gas generation at CHP facilities accounts for about 9 percent of generation in the Interior West by 2020 under the BEP. Energy from renewable resources increases under BAU, but it increases significantly more under the BEP. Generation from nuclear, hydro, and other resources is about the same under both scenarios. More detailed information on the BEP and BAU capacity additions and generation profiles can be found in Appendices C and D.

Fig. 3-18. Generation in the Interior West by Resource: Business as Usual

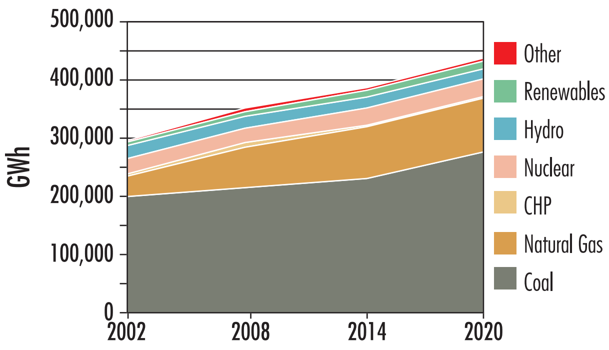


Fig. 3-19. Generation in the Interior West by Resource: Balanced Energy Plan

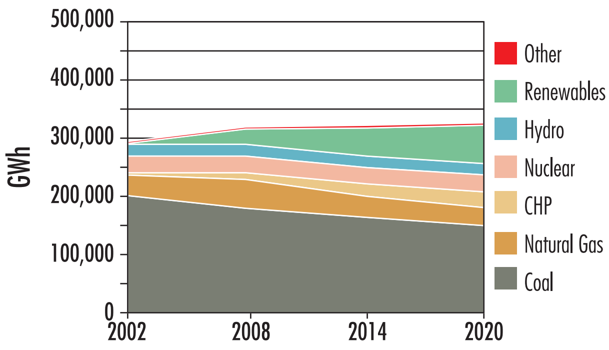
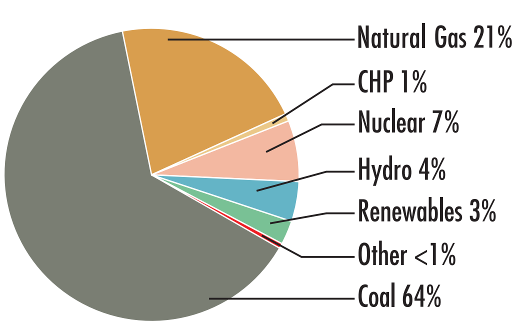
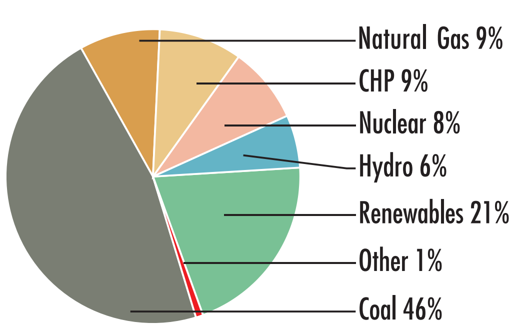


Fig. 3-20. Electric Generation Mix in 2020: Business as Usual



2020 Generation = 435,604 GWh

Fig. 3-21. Electric Generation Mix in 2020: Balanced Energy Plan



2020 Generation = 322,884 GWh

Benefits of the Balanced Energy Plan

As described in this section, the Balanced Energy Plan has lower costs, manages risk better, and has fewer environmental and public health impacts than Business as Usual.

Cost Savings

The Balanced Energy Plan costs less than Business as Usual. Costs are divided into several components as explained below. Capital costs are annualized over the life of the facility to make them compatible with annual fuel and other variable costs. Cost components are:

- Annual production cost, consisting of fuel and operating and maintenance costs.
- Annualized new generation capacity costs, where costs are annualized using a capital recovery factor that reflects facility life and return on investment.
- Annualized transmission costs, including depreciation and return on existing transmission facilities plus annualized costs of new transmission facilities.
- Annualized distribution costs, including depreciation and return on existing distribution facilities plus annualized costs of new distribution facilities.
- Annualized costs of energy efficiency measures and programs over and above those incorporated in the BAU case.
- All other costs, including depreciation and return on existing generation facilities, and utility costs associated with customer accounts and general overhead. These "other" costs are the same in the BAU case and the BEP.

Fig. 3-22. Balanced Energy Plan Savings Relative to Business as Usual

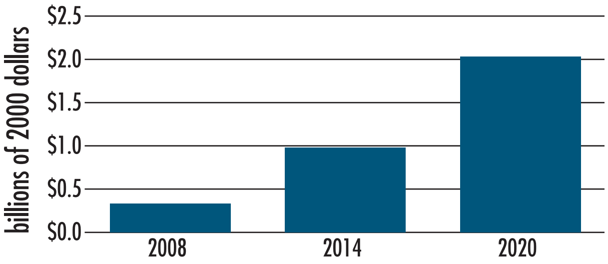


Figure 3-22 shows annual savings due to the Balanced Energy Plan (BAU costs minus BEP costs). By 2020, the Balanced Energy Plan is about $2.0 billion per year less costly in year 2000 dollars. Differences in cost components between the BEP and BAU are shown in Figure 3-23 for 2020. Under the Balanced Energy Plan:

- Production costs are lower because energy efficiency reduces the need for generation and because renewable energy is substituted for fossil fuel generation. Thus, significant fossil fuel costs are avoided.
- New generation capacity costs are higher because renewable energy projects are capital-intensive and have higher up-front costs than some conventional technologies.
- Transmission and distribution costs are lower. The Balanced Energy Plan requires more transmission capacity to move energy from remotely located renewable facilities to the grid and to market. However, the BEP requires fewer transmission and distribution capacity upgrades overall because energy efficiency reduces loads on the transmission and distribution system (Figure 3-24).
- Energy efficiency costs are higher because more energy efficiency measures are included.

Fig. 3-23. Cost Components in 2020: Business as Usual and Balanced Energy Plan

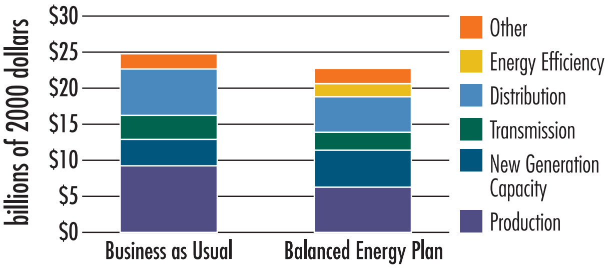
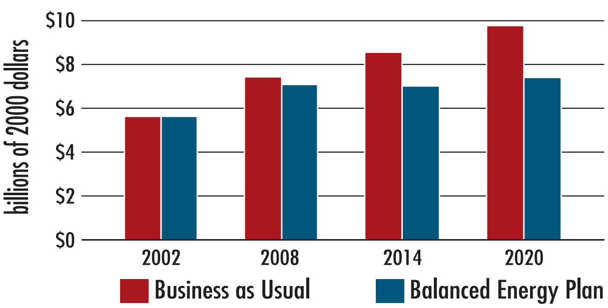


Fig. 3-24. Annualized Transmission and Distribution Costs



Risk Mitigation

Power production in the Interior West is subject to risks. We analyzed several of these risks:

- Rising natural gas prices
- Increased electricity costs from environmental regulations, including limits on carbon dioxide emissions to address climate change
- Reduced hydropower generation because of prolonged drought

To compare how the Balanced Energy Plan and Business as Usual respond to these risks, we evaluated each case under higher-than-expected natural gas prices, future carbon dioxide regulations, and lower-than-expected hydroelectric production due to drought. We also analyzed a scenario in which all three of these events occurred simultaneously. We used the following assumptions:

- Natural gas price risk was analyzed by assuming a 25 percent increase above the base case gas price forecast.
- Carbon dioxide regulatory risks were analyzed assuming that an emissions cap-and-trade program would impose a cost of $5 per ton of carbon dioxide in 2008, increasing to $10 per ton in 2014 and to $20 per ton by 2020. These costs fall in the middle range of recent studies estimating the cost of complying with future carbon dioxide regulations.[8] Future regulation of greenhouse gas emissions may not employ a cap-and-trade approach, but this type of approach is used for other pollutants and has the advantage of lowering the costs of meeting the regulatory requirement. Further, the cost of tradable credits under a cap-and-trade system would tend toward the marginal cost of compliance.
- Risk of reduced hydro output due to drought was analyzed by assuming a 20 percent reduction in water conditions relative to a normal water year. Historically, 10 percent of years experience this level of drought or worse.

Fig. 3-25. Risk Scenarios: Balanced Energy Plan Savings Relative to Business as Usual

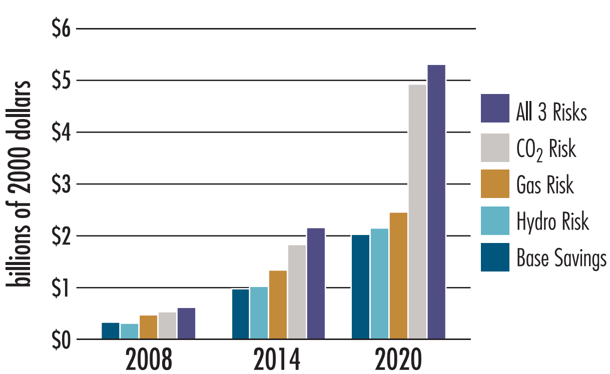


Figure 3-25 shows the difference in total annual costs between the Balanced Energy Plan and the Business as Usual case. The bars corresponding to the base savings represent the difference in costs between the BEP and BAU without any risky events occurring. The bars corresponding to the various risk cases represent the savings from the Balanced Energy Plan that are realized if the risky events do occur. The results indicate that:

- The Balanced Energy Plan is always less costly than Business as Usual. By 2020, the annual savings from the BEP range from $2.0 billion under the base case to $5.3 billion if all three risks occur simultaneously.
- The savings from the Balanced Energy Plan under the hydro and natural gas price risk cases are each about the same as the base savings.
- The savings from the Balanced Energy Plan under the CO_2 risk case are much larger than the base savings or the savings in the other risk cases, especially in 2020.
- The savings from the Balanced Energy Plan are greatest when all three risks occur simultaneously.

We recognize that the elements of the Balanced Energy Plan introduce their own risk into the region's electric system. One of these is that energy from intermittent wind resources may not be available when needed. As discussed earlier, we have taken this risk into account. Another risk is that renewable technologies will perform differently than assumed. However, we do not think this risk is substantial, because most of the renewable technologies included in the BEP are well established and well understood.

There is the risk that the renewable technologies will cost more than we have assumed. However, we have taken care in our cost assumptions. Wind costs are well documented based on numerous recent projects, and we have assumed costs consistent with recent installations. For solar energy, we assumed costs for photovoltaic projects based on costs incurred in 2001 and 2002. However, recent evidence from Arizona suggests that costs have decreased significantly since then, so that costs of installing rooftop and central station photovoltaic systems are actually lower in 2004 than we assumed for 2008.[9] In addition, our solar thermal costs are higher than those currently projected by the National Renewable Energy Lab and the Energy Information Administration.[10] Therefore, we believe that our solar cost assumptions are conservative and that we have probably overestimated these costs. The biggest uncertainty in costs is probably associated with geothermal energy, in which costs are site specific. Our estimates produce costs per kilowatt-hour that fall within the range estimated by developers and other experts, and thus are probably not biased upward or downward.

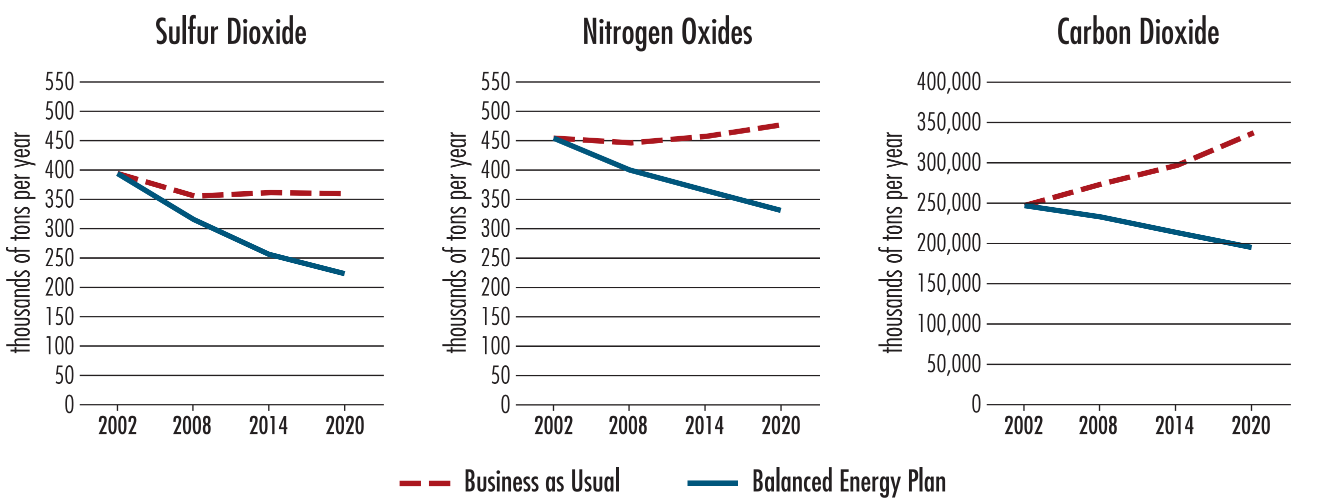
Perhaps the greatest uncertainty inherent in the Balanced Energy Plan is that utilities and their customers will fail to make the investments in energy efficiency or CHP which we have assumed in the plan. As discussed in Chapter 4 we think that these uncertainties can be reduced by encouraging private sector actions and public policy reforms that provide incentives and reduce barriers to the adoption of these technologies. However, recognizing that these uncertainties exist, we also analyzed an Alternative Plan that relies less heavily on energy efficiency and combined heat and power than the Balanced Energy Plan but that has roughly the same carbon dioxide and natural gas consumption profiles. The objective was to develop a scenario that, like the BEP, would act as a hedge against natural gas and carbon risk. To do this we replaced the efficiency and CHP resources with integrated gasification combined-cycle (IGCC) coal plants as well as some additional wind power. IGCC plants burn gasified coal and therefore are not subject to the risk of rising natural gas prices. In addition, these plants can be configured to capture carbon dioxide emissions at lower cost than conventional coal and natural gas power plants, thus reducing the risk of possible future carbon dioxide regulations.

We found that the Alternative Plan was more expensive than the both the Balanced Energy Plan and BAU. However, it does have risk-hedging and environmental benefits that, while not as robust as those of the BEP, are significantly better than BAU – especially with respect to carbon risk. More details on the Alternative Plan and how it compares to Business as Usual and the Balanced Energy Plan, as well as more information on IGCC technologies, can be found in Appendix E.

Reduced Environmental and Public Health Impacts

Air The Balanced Energy Plan's efficiency and renewable energy investments, along with early retirements of older and polluting power plants, dramatically reduce power sector air pollution. Figure 3-26 summarizes differences in power sector emissions under the BEP and BAU. The decrease in SO_2 emissions in the BAU scenario between 2002 and 2008 is attributable to the planned installation of SO_2 pollution control equipment on several coal plants in the region.[11] By 2020, sulfur dioxide emissions are 38 percent lower, nitrogen oxides 31 percent lower, and carbon dioxide emissions 42 percent lower under the Balanced Energy Plan. These lower levels of air emissions are due to reduced fossil fuel generation; we did not assume different emission regulations under the two scenarios. In addition to protecting public health and the environment, these reductions will help decrease the need for costly pollution controls on industrial and manufacturing facilities to comply with current or future federal, state and local air quality requirements.

Fig. 3-26. Air Pollutant Emissions

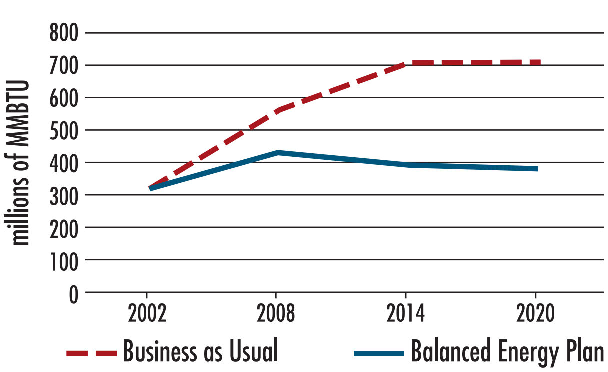


Water The Balanced Energy Plan's lower level of fossil fuel generation also reduces the use of increasingly scarce and valuable water to cool power plants. We estimate that the lower coal and natural gas generation of the BEP will reduce water consumption in the region by about 82 billion gallons (252,000 acre-feet) in the year 2020. This is a 42 percent savings relative to Business as Usual. Water consumption in both cases includes water used for combined heat and power and biomass generation.

Land The lower level of fossil fuels used in the Balanced Energy Plan can reduce the impacts of natural gas and coal extraction on western lands. For example, in 2020 under BAU, annual natural gas consumption by power plants in the Interior West is about 700 million MMBTU, compared to only about 400 million MMBTU under the Balanced Energy Plan (Figure 3-27).

The BEP requires much less gas consumption because energy efficiency reduces peak and intermediate period demand, which is often served by gas-fired power plants, and because renewable energy displaces peak and intermediate period gas-fired generation. The decrease in gas consumption occurs despite the increased use of gas for combined heat and power. For coal-fired power production in 2020, coal consumption is 2.9 billion MMBTU under BAU and 1.7 billion MMBTU under the BEP. This fuel savings should translate into less damage to western landscapes due to a reduced need to extract fossil fuels.

Fig. 3-27. Natural Gas Consumption by the Electric Power Sector in the Interior West



Conclusion

This chapter described the economic and technical basis of a Balanced Energy Plan for the Interior West that offers significant benefits relative to continuation of current trends and policies. The Balanced Energy Plan relies on non-hydro renewable resources to meet approximately 20 percent of the demand for electricity by 2020. The plan also calls for energy efficiency measures that by 2020 reduce electric loads by about 30 percent relative to Business as Usual.

The Balanced Energy Plan represents a departure from the conventional wisdom on how to meet electricity demands in the region. If the BEP is to be implemented it will require innovative public policy and private sector decisions. Chapter 4 provides examples of the successful implementation of some energy innovations and outlines steps for moving the region toward a more balanced energy future.

Endnotes

1. To simplify the levelized cost calculations for the fossil fuel plants, we assumed the fuel cost for the installation year applies over the life of the project. The actual costs used in the PROSYM modeling assume that fuel costs change over time as shown in Figure 3-1.

2. Because of the interconnected nature of the western power grid, we also needed to project demands in California and the Pacific Northwest. For the Pacific Northwest we relied on BAU electricity demand forecasts developed by the Tellus Institute in its report *Clean Electricity Options for the Northwest*. For California, the BAU demand projections were taken directly from the EIA *Annual Energy Outlook 2002*.

3. We expect that costs of energy efficiency in constant dollars will remain relatively stable over the study period. There are two offsetting forces at work. On the one hand, over time, the less costly opportunities will have been addressed, so that the more costly measures constitute a higher percentage of the improvements in later years. On the other hand, technological improvements in energy efficiency should tend to lower the costs of efficiency measures over time.

4. The solar energy category includes photovoltaics and solar thermal technologies. The biomass category includes combined-cycle power plants, landfill gas facilities, and facilities where biomass materials are co-fired with coal.

5. Solar generation, which is also subject to variability, was modeled as follows. Each solar generator (PV and central station) was modeled with three different operating patterns. During the night, the solar generator did not produce any power at all. During the mid-day periods (typically five to six hours), the solar generators were operated at their full-rated capacity levels. During the "shoulder" periods (typically one or two hours on each side of the peak period), the solar generators were operated at derated capacity levels to reflect the lower insolation at those times. The shoulder and peak period durations and capacity levels were chosen such that the total daily and annual capacity factors would match our assumptions of solar generator capacity factors by region.

6. The Seams Steering Group – Western Interconnect (SSG-WI), a regional transmission planning group comprised of utilities from across the West, assumes that a transmission path is heavily utilized if it is loaded to at least 75 percent capacity at least 50 percent of the time. This is a somewhat higher threshold for determining that a transmission path is congested than used in our analysis. For more on the SSG-WI transmission congestion indicators, see *Framework for the Expansion of the Western Interconnection, Report of the Seams Steering Group – Western Interconnection*. October 2003. pp. 14-15.

7. Electricity consumption and export figures include transmission and distribution losses.

8. See, for example, Newell, R. and R. Stavins. 2000. Climate Change and Forest Sinks: Factors Affecting the Costs of Carbon Sequestration. *Journal of Environmental Economics and Management* 40:211-235; Kolstad, C. and M. Toman. 2001. *The Economics of Climate Policy.* Discussion Paper 00-40REV. Washington, DC: Resources for the Future; Burtraw, D., K. Palmer, R. Bharvirkar and A. Paul. 2001. *The Effect of Allowance Allocation on the Cost of Carbon Emission Trading.* Discussion Paper 01-30. Washington, DC: Resources for the Future; David, J. and H. Herzog. *The Cost of Carbon Capture.* 5th International Conference on Greenhouse Gas Control, Cairns, Queensland, Australia, August 14-16, 2000; Energy Information Administration. *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide.* SR/01AF/2000-05. Washington, DC: U.S. Department of Energy; Plantinga, A., T. Mauldin and D. Miller. 1999. An Econometric Analysis of the Costs of Sequestering Carbon in Forests. *American Journal of Agricultural Economics* 81:812-824; Tellus Institute and Stockholm Environment Institute – Boston Center. 2001. *The American Way to the Kyoto Protocol* (prepared for the World Wildlife Fund); PacifiCorp Integrated Resource Plan Carbon Dioxide Environmental Adder Policy Choices, July 2002; Repetto, R. and J. Henderson. 2003. Environmental Exposures in the U.S. Utility Industry. *Utilities Policy* 11:103-111.

9. Tucson Electric Power Company. Utility Scale Solar Photovoltaic Distributed Generation, presented to the Arizona Corporation Commission, April 5, 2004; Cost Evaluation Working Group. *Costs, Benefits, and Impacts of the Arizona Environmental Portfolio Standard.* Arizona Corporation Commission, June 30, 2003.

10. Energy Information Administration. 2003. *Annual Energy Outlook 2002.* Washington, DC: U.S. Department of Energy; NREL Energy Analysis Office. Renewable Energy Cost Trends. http://www.nrel.gov/analysis/docs/cost_curves_2002.ppt.

11. These are the Mohave plant in Nevada and the Valmont, Cherokee and Arapahoe plants in Colorado.

All website references verified May 1, 2004.

Chapter 4 Moving the Interior West toward a More Balanced Energy Future

Introduction

The Balanced Energy Plan presented in this report is less costly than Business as Usual, helps manage fuel-price, environmental and drought risks, is just as reliable and is much better for public health and the environment. Westerners have an enormous stake in its implementation.

Under the Balanced Energy Plan, businesses will find their energy costs decreasing over time, making them more competitive. Other utility customers will find that they are spending a lower percentage of their income on utility bills. Utilities and businesses will reduce their exposure to risks and future costs. The Balanced Energy Plan is easier on the land than Business as Usual, protecting the interests of ranchers, the recreation industry and rural local governments. Cities will be better able to improve their air quality. The region will also help reduce the risks, costs and eventual liabilities of the largest environmental challenge facing the planet – global climate change. Under the BEP, the entire region will save billions of dollars to invest in other economic activities. Most importantly, through our actions in implementing the plan, we will be safeguarding the region's economy and natural environment for future generations.

These benefits, however, will not be realized on their own. There are barriers that limit investments in the energy resources that are key elements of the Balanced Energy Plan. Fortunately, there is growing evidence from both the private and public sectors that shows that these barriers can be overcome and the many benefits of the BEP realized.

This chapter begins with a brief description of barriers facing the BEP. It then presents a series of examples that show how businesses and public policy makers are breaking down these barriers. Drawing from these examples, the chapter concludes with a set of guidelines the region can follow to encourage movement toward a more balanced energy future.

Barriers to the Balanced Energy Plan

The barriers to investments in energy efficiency, renewable energy and combined heat and power resources (hereafter referred to as BEP resources) have been described in detail in many reports.[1] We do not repeat these details here. Instead, we describe the major categories of barriers as a context for the remainder of the chapter.

Focus on the short run

The typical cost profile of the BEP resources is higher front-end capital investment, low life-cycle costs and low long-run risks. A problem for technologies with this profile is that energy consumers, investors and regulators often focus on minimizing short-run outlays. Faced with competition, political pressure or lack of access to financial resources, we make decisions that sharply discount the future. Our decisions do not fully take into account future risks and costs, and we ignore the fact that our energy decisions will affect our own finances and reverberate through the economy and environment for decades to come. Remedies include technological innovations that can lower front-end costs, entrepreneurial willingness to tap into and develop markets for these resources despite their higher short-term costs, and public policies to steer additional financial investment toward BEP resources.

Focus on the familiar

In addition to the short-run focus is the tendency to go with what we know. On the electricity supply side, that usually means deploying technologies that use fossil fuels. On the demand side, it means that buildings and lighting and other equipment are typically less energy efficient than they could be. There are transaction costs – in money, time and effort – in learning about new technologies, and there are doubts about the performance of new technologies or their role in meeting demand, often based mainly on the lack of experience with them. The focus on the familiar may cause utilities and others to forego investments in non-traditional technologies even when they are less expensive than the alternatives. Remedies include training and education about new technologies and gaining hands-on experience through initial projects.

Regulatory barriers

Utility and other regulatory barriers curtail cost-effective investment in BEP technologies. These barriers include:

- Retail electric rates that do not clearly communicate costs that are avoided when customers reduce consumption
- Failure to seriously consider a full range of alternatives when planning for resources to meet growing demand
- Regulation that allows utilities to pass on to customers future risks and costs of utility resource decisions over which customers have no control
- Failure to fully recognize the environmental costs of electricity production
- Regulation that allows obstacles to non-utility-owned combined heat and power and distributed renewable resources
- Transmission planning, access and pricing policies that discourage intermittent renewable resources and fail to recognize the benefits of energy efficiency and distributed resources in relieving transmission congestion

Remedies include integrated resource planning, electric rate design reform, equal treatment of non-utility generation, and transmission planning reform.

We believe these barriers need not block implementation of the BEP. Examples from both the private and public policy sectors support our optimism.

Toward a Balanced Energy Future: Examples from the Private Sector

Businesses and other private sector decision makers can play an important role in moving the Interior West toward a balanced energy future. Below we describe several success stories where companies have taken innovative steps to reduce barriers and increase the use of efficiency, renewables, and combined heat and power resources.

PacifiCorp: Resource planning that recognizes future climate change regulatory risk[2]

PacifiCorp is a major western utility serving approximately 1.5 million customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. Following the California electricity crisis of 2000 and 2001, the company revamped its resource planning process to more thoroughly address growing risks and long-term costs faced by its customers and shareholders.

In 2003 PacifiCorp presented a comprehensive resource plan for meeting the growing electric service requirements of its customers through 2012. In addition to carefully analyzing natural gas price risk, the company incorporated risks and costs of future climate change and other environmental regulations into its decision-making process. With respect to climate change risk, PacifiCorp evaluated various resource portfolios assuming an $8 cost adder for each ton of carbon dioxide produced.

Recognition and evaluation of climate change regulatory risks by a major electric utility in the West is an important step along the road to a more balanced energy future for the region.

IBM: Stabilizing electricity costs by purchasing renewable energy[3]

IBM has a history of energy management dating back to the 1970s. The company currently has a corporate goal to achieve an annual 4 percent savings in electricity and fuel use. Designed to provide employees with an incentive to reduce costs, improve competitiveness and protect the environment, the corporate goal can be met through improved energy efficiency or by the increased use of renewable energy.

In response to this goal, the energy manager at IBM's facility in Austin, Texas began purchasing a renewable energy product offered by Austin Energy, the local utility. The price of renewable energy was slightly higher than conventional fossil power, but unlike the price of conventional power, which fluctuated with changes in fuel prices, renewable energy was offered at a fixed rate through 2011.

IBM initially predicted that renewable power would cost $30,000 more per year, but opted for the purchase anyway due to three factors:

- The fixed-price contract provided a hedge against possible higher electricity costs due to fuel price increases.
- The cost stability helped IBM manage its energy budget.
- The renewable energy purchases helped IBM manage greenhouse gas emissions.

Ultimately, conventional power costs increased due to higher fuel prices, leading to a $20,000 electricity bill savings for IBM in its first year in the program. IBM expects that fuel prices will again increase conventional power costs and that corporate savings will be over $60,000 in 2004. These savings go directly to IBM's bottom-line profitability. In addition, IBM estimates that its renewable energy purchases will avoid roughly 8250 tons of carbon dioxide emissions per year.

IBM's Austin experience highlights two issues regarding increased renewable energy use. First, IBM's renewable energy purchases would not have occurred if the company had focused only on the expected higher short-term costs. A longer-term view that considered the potential for renewable energy to hedge against fuel price risk, as well as recognition of the environmental benefits, were critical factors in making the renewable energy purchases. Second, IBM's experience demonstrates how setting corporate energy management goals can lead employees to seek out and realize the cost-reduction benefits that renewables and efficiency have to offer.

Alcoa: Identifying and capturing industrial energy savings in Utah[4]

Alcoa, the world's leading aluminum producer, owns and operates an aluminum plant in Spanish Fork, Utah. Aluminum production is an energy-intensive industry, and the plant is a large user of both electricity and natural gas. In July 2000, the Industrial Assessment Center at Colorado State University conducted an energy assessment of the plant and identified a number of measures to reduce energy consumption. Measures implemented as of September 2002 reduced electricity consumption by roughly 454,300 kWh per year and natural gas consumption by roughly 24,000 million BTUs per year. Total cost savings are estimated at $245,000 per year. With an implementation cost of approximately $105,000, the simple payback period for the efficiency measures was just over five months.

Alcoa's experience at its Spanish Fork plant illustrates that even highly cost-effective energy efficiency measures with short payback periods may be untapped, because electricity consumers are simply not aware of available efficiency measures or the amount of money and energy that would be saved if they were adopted. In many firms, especially small and medium-sized enterprises, plant engineers and managers may not understand how to optimize energy use or may simply not have the resources to identify energy savings opportunities. This example shows that a lack of information can be overcome by developing and supporting programs like Colorado State's Industrial Assessment Center that provide expertise and training to energy users in the region.

PPM Energy: Renewable energy development as a business strategy[5]

A corporate affiliate of PacifiCorp, PPM Energy develops and markets wind energy, natural gas storage projects, and combined heat and power projects, serving wholesale electricity customers such as investor-owned utilities, municipal utilities, rural electric cooperatives and large industrial customers. PPM offers services in many aspects of wholesale power and gas markets, leveraging assets and expertise in three core business lines:

- Renewable generation and development
- Natural gas-fired thermal generation and development
- Natural gas storage

By taking advantage of synergies across these business lines, PPM is able to offer customers strong energy and risk management capabilities. With this innovative combination, PPM has taken a leading role as a developer and wholesaler of renewable energy. By the end of 2003, the company owned, or had wholesale contract rights on, 830 MW of wind power. The company's goal is to have 2000 MW of wind power under control by 2010. PPM's access to wholesale power markets allows it to combine wind-generated energy with wholesale power purchases to assure customers that their power will be delivered as needed. In essence, PPM is able to "trade around" its physical wind assets to address wind's intermittency and to provide competitive, stably priced, zero-emission wind power.

PPM is an example of how creative development of a market niche can overcome barriers to renewable energy and how renewables can be a core component of a successful business strategy. As shown in the accompanying box, PPM is not alone when it comes to recognizing market opportunities for renewable energy.

Large Companies Engaged in Renewable Technologies

Photovoltaics

• Sharp • BP Solar • Kyocera • Shell Solar • Sanyo

Wind Power

• GE Wind • NEG Micon/Vestas • Mitsubishi • FPL Energy • Shell Wind Power

Biomass Power

• Foster Wheeler • Caterpillar

Concentrating Solar Power

• Solargenix Energy • Gamesa • FPL Energy • Constellation

Geothermal

• Calpine • Mitsubishi • Toshiba • Fuji

CMS Viron Energy Services: Using energy performance contracts to save Nevada taxpayers money[6]

CMS Viron Energy Services is a Kansas City–based energy services company and a pioneer in developing energy performance contracts that allow customers to finance energy efficiency investments using the dollar savings from energy efficiency projects. CMS Viron and the State of Nevada entered into an energy performance contract to reduce energy use at the State Capitol Complex. Under the contract \$1.9 million in energy efficiency measures were implemented in 20 buildings. CMS Viron projects savings of more than \$3 million in energy costs, \$148,000 in water costs and \$69,000 in operation and maintenance costs over the 12-year contract period. Thus the net savings to Nevada are expected to be in excess of \$1 million.

Nevada's experience working with CMS Viron is an example of how energy service companies and energy performance contracts can help overcome a number of barriers to energy efficiency investments. First, because of their expertise in identifying and implementing efficiency measures, energy service companies help overcome information barriers. Second, performance contracts typically guarantee energy savings levels, thus alleviating concerns that customers may have regarding the performance of efficiency measures. Finally, by allowing customers to finance efficiency measures out of energy savings, performance contracts overcome capital and financing constraints.

Toward a Balanced Energy Future: Examples from the Public Policy Sector

While private sector leadership is essential in moving the region toward a balanced energy future, public policy also has critical role to play. Public policy shapes the context in which private sector energy decisions are made and helps ensure that private decisions take into account broader public interests such as reducing risks and long-term costs and protecting public health and the environment. This section presents examples of how policies implemented at the state and regional level are removing barriers and providing incentives for increased use of renewables, efficiency, and combined heat and power in the Interior West.

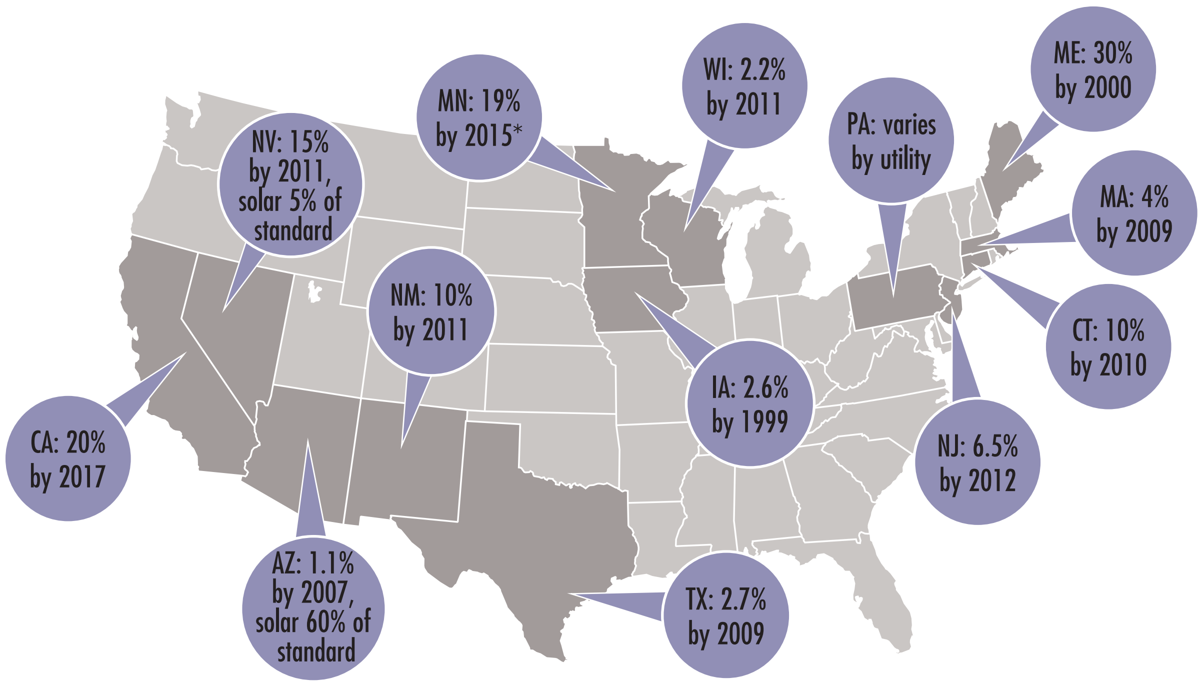
Renewable Energy Standards: Encouraging the market to develop renewable resources[7]

A renewable energy standard is a governmental requirement that electric utilities obtain a specified amount of the electricity they sell at retail from eligible renewable resources. As indicated in Chapter 3, renewable energy standards have been adopted in Arizona, Nevada, and New Mexico, and they are used in other western states as well, notably California and Texas. Renewable standards foster development of renewable energy by overcoming barriers to acquisition of renewable energy in the following ways:

- They focus utilities on understanding how to use renewable resources in their generation and transmission systems, thereby helping to overcome unfamiliarity with renewable energy technologies. For example, utilities that buy energy from large wind projects learn how to accommodate intermittent resources.
- They provide some regulatory certainty for utilities regarding cost recovery for acquiring energy from resources that are not always cost competitive with conventional technologies.
- They create markets for renewable energy and can lead to large, multi-year orders for renewable energy generating equipment, thereby lowering manufacturing costs and creating more market certainty for vendors.
- They encourage active searches for cost-effective utility applications of renewable energy.
- They can create new revenue sources for utilities that sell tradable renewable energy credits or tradable emission reduction credits derived from renewable energy.

To add flexibility and reduce the costs of meeting the renewable energy requirement, tradable renewable energy credits are sometimes used. Credit trading allows electricity suppliers who can most cost-effectively meet the standard to generate extra renewable energy and sell credits to utilities with higher renewable generation costs. A renewable energy standard with a tradable credit system uses market mechanisms to ensure that the standard is met at least cost and with a minimum of ongoing administrative involvement by government.

Fig. 4-1. Renewable Energy Standards



Source: Union of Concerned Scientists. 2003.
* MN has a minimum requirement for one utility, Xcel Energy.

Western Renewable Energy Generation Information System: Building institutions to support renewable energy development[8]

The ability to track renewable generation and verify compliance is critical to successful implementation of renewable energy standard policies. A tracking system also ensures that electricity customers who are making voluntary renewable energy purchases are getting what they pay for.

In recognition of these needs, the Western Governors' Association and the California Energy Commission are working to develop the Western Renewable Energy Generation Information System. WREGIS will serve as an independent tracking system to provide data necessary to substantiate generation from renewable resources and support verification, tracking and trading of renewable energy credits in the western United States. The system is expected to be operational by 2005.

By establishing common definitions, rules and operating guidelines for the creation and trading of renewable energy credits, WREGIS will reduce costs incurred by both government agencies and electricity suppliers in verifying compliance with renewable energy standards and other renewable energy policies. This regional tracking system will also lower transaction costs for trades of renewable energy credits. In addition, WREGIS will support the development of more robust renewable energy markets in the West, since tradable credits help overcome transmission and other issues inherent in purchases of renewable energy.

Addressing Regional Haze in the West: Valuing the environmental benefits of renewable energy and energy efficiency[9]

By reducing power sector emissions, renewable energy and energy efficiency investments help address air quality problems in the region. Unfortunately, air quality regulatory programs typically do not recognize these benefits or reward companies that make investments in clean energy technologies.

The western component of EPA's regional haze rule is an exception. Under this rule, certain western states can meet their haze reduction requirements by opting into a western component of the rule. Those states that opt in receive credit for expanding their use of renewables and efficiency as part of a comprehensive emission reduction strategy that must also include efforts to reduce emissions from power plants, other industrial sources and automobiles.[10]

Incorporating energy efficiency and renewable energy projects into state regional haze plans was recommended to EPA by the Western Regional Air Partnership. The WRAP is an organization of western states and tribes working to address air quality problems in the region. The decisions of the WRAP are informed by a wide range of interests including industry, federal land management agencies, state and local governments, and environmental groups. Based on the WRAP's recommendations the western component of the regional haze rule calls for the expansion of energy efficiency efforts and sets a regional renewable energy goal that 20 percent of the region's electricity consumption should come from renewable resources by 2015. States opting into the western component of the rule must include in their emission reduction plans strategies and policies to increase energy efficiency and move toward the renewable energy goals.

The western component of the regional haze rule is an example of air quality regulators recognizing the environmental benefits of energy efficiency and renewable energy and pursuing new regulatory mechanisms to encourage their development. Five states – Arizona, New Mexico, Oregon, Utah and Wyoming – have opted in to the western component.

The Rocky Mountain Area Transmission Study: Integrating wind and energy efficiency into transmission planning[11]

In September 2003, the governors of Utah and Wyoming kicked off the Rocky Mountain Area Transmission Study (RMATS), an innovative public process for the development of upgrades and additions to the transmission systems that serve Utah, Wyoming, Colorado, Idaho, and Montana. Typically, transmission planning has tended to ignore renewable resources, energy efficiency, and environmental issues. The RMATS study takes these matters seriously, adds broad public participation and review, and analyzes both new transmission lines and alternatives to new line construction.

The voluntary RMATS process is open to all interested participants. The steering committee consists mainly of state officials. All of the region's utility transmission owners participate, along with representative investor-owned utilities, generation and transmission co-ops, public power agencies, generation developers, environmental groups, and state regulatory commissions.

A central part of the RMATS study is examining the extent to which new transmission lines are needed in order to tap into the region's wind resources. The study also examines steps that can be taken to provide wind resources better access to the existing transmission system. In addition, the study addresses how energy efficiency can relieve congestion on existing lines and reduce the need for new transmission and generation. The study will also examine a number of risk scenarios designed to test how the transmission system would perform under varying assumptions concerning natural gas prices and future carbon taxes.

The RMATS study is an example of a planning process that recognizes and evaluates the infrastructure investments that will be needed to move the region toward a more balanced energy future as well as the benefits that renewable energy and energy efficiency can provide to electricity customers across the region.

The City of Phoenix: Providing stable funding for energy efficiency[12]

The energy management program established by the City of Phoenix in the 1970s is a model for developing stable funding sources for energy efficiency projects at the local level. In 1984, the city started the Energy Conservation Savings Reinvestment Plan with money from state oil overcharge funds. This plan provides funding for energy efficiency projects. Half the savings from these projects goes back into the reinvestment plan and half goes into the city's general fund. Between 1978 and 2000 the city estimated that it saved $42 million from energy efficiency improvements.

Phoenix also uses the fund to help pay for new energy-efficient equipment used by the city. The fund has paid for many low-tech measures like lighting, motors and chillers, and has also financed a district cooling system and a thermal storage system for the new Phoenix City Hall.

One of the keys to the program's success has been city's focus on developing in-house expertise to plan and monitor energy efficiency measures and to calculate efficiency costs and savings. The city also established an Energy Conservation Team that included representatives from all municipal departments. It brought department managers on board by promising support for their budgets through participation in the program. Another key to the success of the Phoenix model has been the recognition that roughly 8 to 15 percent of any energy efficiency project should be reserved for maintenance and training.

Utah Public Service Commission: Using price signals to encourage energy efficiency[13]

In January 2004, the Utah Public Service Commission approved new electric rate designs aimed at providing PacifiCorp's retail customers with economic incentives to use electricity more efficiently in the summer, when power plants are running hardest and electricity is most costly to produce. For residential customers the commission adopted an "inverted block rate" structure where the price of electricity increases with use. During summer months, when electricity demand is highest, residential electricity prices will be

6.7 cents per kWh for electricity use up to 400 kWh per month, 7.6 cents per kWh for use between 400 and 1000 kWh, and 9 cents per kWh for use over 1000 kWh. Higher summer rates were also approved for commercial and industrial customers. The new rate structures send customers price signals that more accurately reflect the costs of producing electricity.

The impetus behind the new rate structures was the desire to reduce the continued pressure to build new power plants and transmission and distribution facilities to satisfy growing electric demands along Utah's Wasatch Front. Utah's inverted block rates are an example of using price signals as a policy tool to promote increased energy efficiency and conservation during times when saving energy matters most.

The Path Forward

The foregoing examples provide evidence that we can overcome the barriers to the implementation of the Balanced Energy Plan. However, much more needs to be done if these examples are to become the norm rather than the exception.

The experience of Western Resource Advocates in promoting sustainable energy in the Interior West for over a decade, together with the examples described above, lead us to propose the following guidelines for moving the region toward a balanced energy future.

Business needs to lead the way

Businesses in the West have found ways to become more competitive, reduce costs, and increase profits by investing in or using BEP resources. It is business – utilities, large electricity users, energy service companies, and renewable energy and combined heat and power developers – on whom we must depend primarily for the implementation of the BEP. Businesses control the flow of most of the capital that could be invested in BEP technologies. Businesses see the opportunities, risks, and benefits that these technologies can provide in their operations and markets better than anyone else. Corporate policies that recognize the value of BEP resources are critical foundations for progress toward a balanced energy future.

The examples presented above suggest several actions corporations can take to better seize these opportunities. For large industrial electricity users, setting corporate energy efficiency and renewable energy goals and standards can send clear signals about intentions and can encourage employees to seek out cost-effective opportunities to utilize BEP resources. The savings go to the corporate bottom line in the form of increased profits. Businesses can train and educate employees to recognize energy savings opportunities and they can budget for and fund clean energy investments. Finally, businesses can support public policies that encourage investments in BEP resources.

Government needs to set policies and standards for businesses and others to meet

The context in which businesses and consumers make energy investment decisions can be shaped in part by public policies. A wide variety of policies may be used to set standards and provide economic incentives that encourage increased investments in BEP resources. Among the most important are:

- Renewable energy standards that set minimum requirements for renewable energy sales
- System benefits charges that raise funds through a small charge in customers' retail electric rates to support investment in BEP resources
- Strong building codes that encourage energy-efficient new construction coupled with education, training and building inspection to maximize energy savings
- Utility energy efficiency programs that provide incentives to regulated utilities to pursue efficiency measures whenever the life-cycle costs of efficiency investments are less than those of alternative generation resources
- Fair interconnection standards, standby rates and electricity buyback rates that reduce barriers to non-utility-owned combined heat and power and distributed renewable resources
- Environmental regulations such as emission cap-and-trade programs that provide incentives to invest in cleaner energy technologies
- Continued federal support of clean energy technologies through appropriations and tax policy to encourage technological innovation and industry development

In addition to setting policies, government agencies, as electricity consumers and operators of government facilities, can lead by example by purchasing renewable energy and by investing in energy efficiency and combined heat and power resources.

Recognize and manage risks and costs

The analysis in Chapter 3 shows that the BEP resources will reduce the region's exposure to fuel-price, environmental and drought risks. These risks have the potential to become tomorrow's costs. Recognition and evaluation of these risks and costs, and an understanding of how BEP resources can be used to help manage them, are critical ingredients of a balanced energy future.

Utility integrated resource planning is an important tool that can be used to systematically identify and manage the full set of risks and costs associated with electricity consumption. State public utility commissions should work with utilities, businesses, consumers, environmental groups, and others to implement effective resource planning processes in their states that recognize and manage risks and costs.

Get prices right

It is important that, as much as possible, prices for electricity track the full costs that utilities avoid when customers increase their efficiency of energy use. Doing so sends appropriate price signals that encourage customers to increase efficiency during those hours of the day or seasons of the year when electricity is more costly to produce. Unfortunately, most electric rates do not send cost-based price signals. Utilities and state public utility commissions should explore inverted block rate designs and time-of-use pricing as ways to send appropriate price signals to customers, and they should consider all costs that are not included in today's electricity prices when making decisions about generation resources and alternatives.

Think regionally

The West is an integrated electric region. Yet electric power production is largely regulated at local, state and federal levels. At times this can make it very challenging to encourage regional cooperation and action. In certain areas, however, regional thinking will facilitate movement toward a balanced energy future, and states should strive to develop regional approaches where they would be helpful. One example is regionwide transmission planning to help ensure that remotely located renewable resources can be delivered to population centers and that the congestion-reducing benefits of energy efficiency and combined heat and power generation are recognized.

Another area where regional thinking could be beneficial is in the design of renewable energy standards. Typically, as a means of securing construction jobs and other local economic benefits, the state standards that have been enacted in the region either require or encourage in-state resources to be used for compliance. While this may yield local economic benefits, foreclosing the use of potentially lower cost out-of-state resources can lead to higher costs of complying with the standard. A more regional approach, such as a regional energy standard, could lower costs. The WREGIS renewable energy tracking system currently under development could facilitate and support compliance with a regional renewable energy standard.

Encourage dialogue among key players

Whether the Interior West achieves a balanced energy future depends on thousands of decisions made by utilities, independent power producers, businesses, utility customers, state regulators and many others. The likelihood that these decisions will coalesce to move us toward a balanced energy future increases if there are opportunities for regional discussions about our energy choices. There are number of important forums across the West where this dialogue is already taking place, including the Western Governors' Association, the Western Regional Air Partnership, and regional transmission planning forums such as RMATS. Western Resource Advocates strongly supports these and like-minded efforts and strives to participate constructively in them. We hope the Balanced Energy Plan will help inform the dialogue on energy choices with businesses, utilities, policy makers and others about the stakes involved in our region's energy future.

Endnotes

1. See, for example, Geller, H. 2003. *Energy Revolution: Policies for a Sustainable Future.* Washington, DC: Island Press; Brown, M. 2001. Market Failures and Barriers as a Basis for Clean Energy Policies. *Energy Policy* 29:1197-1208; Eto, J., C. Goldman and S. Nadel. 1998. *Ratepayer-Funded Energy Efficiency Programs in a Restructured Electricity Industry: Issues and Options for Regulators and Legislators.* Washington, DC: American Council for an Energy-Efficient Economy; Jochem, E. 2000. Energy End-Use Efficiency. In *World Energy Assessment: Energy and the Challenge of Sustainability*. New York: United Nations Development Programme; Martinot, E. and O. McDoom. 2000. *Promoting Energy Efficiency and Renewable Energy: GEF Climate Change Projects and Impacts.* Washington, DC: Global Environmental Facility; Nogee, A., S. Clemmer, B. Paulos and B. Haddad. 1999. *Powerful Solutions: Seven Ways to Switch America to Renewable Electricity.* Cambridge, MA: Union of Concerned Scientists; Alderfer, B., M. Eldridge and T. Starrs. 2000. *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects.* NREL/SR-710-28053. Golden, CO: National Renewable Energy Laboratory.

2. PacifiCorp. *Integrated Resource Plan 2003.* http://www.pacificorp.com/File/File25682.pdf.

3. World Resources Institute, Green Power Market Development Group. Corporate Case Studies. Stabilizing Energy Costs: How IBM's Austin Facility Hedged Fossil Fuel Prices by Purchasing Green Power. http://www.thegreenpowergroup.org/case_studies.html.

4. U.S. Department of Energy. 2001. *Best Practices Assessment Case Study: Aluminum.* IAC Energy Assessment of Spanish Fork Plant. DOE/GO-102001-1375; Case Study: Alcoa North American Extrusions Plant. http://www.swenergy.org/casestudies/utah/alcoa.htm.

5. Further information on PPM at http://www.ppmenergy.com.

6. Case Study: Nevada State Capitol Complex. http://www.swenergy.org/casestudies/nevada/capitol.htm; Energy-Efficiency Projects Multiply in Nevada as Performance Contracting Takes Firm Root. http://www.rebuild.org/news/newsdetail.asp?NewsID=1747.

7. Williamson, R. 1998. *Portfolio Approach to Developing Renewable Resources.* Washington, DC: Renewable Energy Policy Project; Wiser, R. and O. Langniss. 2001. *The Renewables Portfolio Standard in Texas: An Early Assessment.* LBNL-49107. Berkeley, CA: Lawrence Berkeley National Laboratory; Cost Evaluation Working Group. *Costs, Benefits, and Impacts of the Arizona Environmental Portfolio Standard.* Arizona Corporation Commission, June 30, 2003; New Mexico Public Regulation Commission. Final Order Adopting 17.9.573 NMAC, Utility Case No. 3619, December 17, 2002; New Mexico Legislature 2004 – SB43: Renewable Energy Act.; Berry, D. 2002. The Market for Tradable Renewable Energy Credits. 2002. *Ecological Economics* 42(3):369-379.

8. Further information on WREGIS at http://www.westgov.org/wieb/wregis/.

9. See Environmental Protection Agency, 40 CFR Part 51 Regional Haze Regulations Final Rule. More information on the Regional Haze Rule as it applies to the West can be found at http://www.wrapair.org/.

10. The Regional Haze Rule is divided into Sections 308 and Sections 309. Section 308 applies nationally. Section 309 is an optional western component that is open to the nine states that comprise the Grand Canyon Visibility Transport Region (GCVTR) that was established as part of the 1990 Clean Air Act Amendments. These states are Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah and Wyoming. These states may either opt in to the western component of the rule or meet their regional haze obligations by complying with Section 308.

11. See Hamilton, R. et al. *Integrating Wind and Demand-Side Management into Transmission Planning: The Rocky Mountain Area Transmission Study* (forthcoming). More information on RMATS can be found at http://psc.state.wy.us/htdocs/subregional/home.htm.

12. http://www.iclei.org/cases/c011-per.htm

13. Public Service Commission of Utah Docket No. 03-2035-02, In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Service Schedules & Electric Service Regulations. January 30, 2004 Report and Order.

All website references verified May 1, 2004.

Appendix A Cost and Performance Assumptions for New Generating Facilities

Fig. A-1. Cost and Performance Assumptions for New Generating Facilities Installed 2003–2008 (2000 dollars)

	Coal	Natural Gas			Wind †					Solar			Biomass			Geothermal
	Pulverized	Combined Cycle	Combustion Turbine	CHP*	Class 4	Class 5	Class 6	Class 7	BEP Average Wind Resource	Central PV	Rooftop PV	Solar Thermal	Landfill Gas ‡	Combined Cycle ‡	Co-firing in Existing Coal Plant §	
Design and Construction																
Typical plant size (MW)	400	250	100	50	150	150	150	150	150	1	0.002	50	5	–	–	50
Overnight capital cost ($/kW)	1,110	453	336	730	924	924	924	924	924	5,400	9,177	5,400	1,399	–	–	2,340
Capital Recovery Factor	19.90%	15.90%	15.70%	15.80%	12.80%	12.80%	12.80%	12.80%	12.80%	12.60%	12.60%	13.60%	15.10%	–	–	15.10%
Operation																
Fuel cost ($/mmbtu)	0.98	4.42	4.42	4.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	–	–	0.00
Heat rate (btu/kWh)	9,331	7,113	8,766	5,000	0	0	0	0	0	0	0	0	11,000	–	–	0
Fixed O&M ($/kW)	22.36	11.30	9.37	0.00	26.60	26.60	26.60	26.60	26.60	10.24	10.18	48.19	153.46	–	–	81.85
Var O&M ($/MWh)	2.55	2.08	0.10	9.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	–	–	0.00
Typical capacity factor	87.00%	57.00%	30.00%	91.00%	32.00%	34.00%	38.00%	44.00%	39.00%	30.00%	20.00%	37.00%	91.00%	–	–	95.00%
Annual Generation (MWh)	3,048,480	1,248,300	262,800	398,580	420,480	446,760	499,320	578,160	512,460	2,628	4	162,060	39,858	–	–	416,100
Annual Fuel Consumption (mmbtu)	28,443,955	8,878,827	2,303,750	1,992,900	0	0	0	0	0	0	0	0	438,438	–	–	0
Emission Rates																
SO_2 (lb/MWh)	0.611	0.006	0.008	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.022	–	–	0.000
NO_X (lb/MWh)	0.984	0.210	0.701	0.100	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	4.103	–	–	0.000
CO_2 (lb/MWh)	1837.427	845.653	1025.642	585.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	–	–	0.000
Cost of Energy																
O&M (cents/kWh)	0.55	0.43	0.37	0.92	0.95	0.89	0.80	0.69	0.78	0.39	0.58	1.49	1.93	–	–	0.98
Fuel (cents/kWh)	0.91	3.14	3.87	2.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	–	–	0.00
Capital (cents/kWh)	2.90	1.44	2.01	1.45	4.22	3.97	3.55	3.07	3.46	25.89	66.00	22.66	2.65	–	–	4.25
Total (cents/kWh)	**4.36**	**5.02**	**6.24**	**4.58**	**5.17**	**4.86**	**4.35**	**3.76**	**4.24**	**26.28**	**66.58**	**24.15**	**4.58**	**–**	**–**	**5.23**

Dash indicates new units not deployed in time period indicated.

* CHP capital costs, emissions, and heat rates are incremental values in addition to boiler or hot water facility costs or characteristics.

† Wind costs do not include federal production tax credit.

‡ Carbon dioxide emissions for biomass combined-cycle unit and landfill gas unit are net emissions, relative to emissions from alternative use of biomass or landfill gas.

§ Capital cost pertains to adding co-firing capability to existing coal units. Co-firing data pertain to specific existing plants in Colorado and Montana, some of which have very low coal costs.

Fig. A-2. Cost and Performance Assumptions for New Generating Facilities Installed 2009–2014 (2000 dollars)

	Coal	Natural Gas			Wind †					Solar			Biomass			Geothermal
	Pulverized	Combined Cycle	Combustion Turbine	CHP*	Class 4	Class 5	Class 6	Class 7	BEP Average Wind Resource	Central PV	Rooftop PV	Solar Thermal	Landfill Gas ‡	Combined Cycle ‡	Co-firing in Existing Coal Plant §	
Design and Construction																
Typical plant size (MW)	400	250	100	50	150	150	150	150	150	1	0.002	50	5	–	400	50
Overnight capital cost ($/kW)	1,083	448	333	730	909	909	909	909	909	4,770	7,504	4,770	1,399	–	200	2,259
Capital Recovery Factor	19.90%	15.90%	15.70%	15.80%	12.80%	12.80%	12.80%	12.80%	12.80%	12.60%	12.60%	13.60%	15.10%	–	19.90%	15.10%
Operation																
Fuel cost ($/mmbtu)	0.95	4.78	4.78	4.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	–	0.65	0.00
Heat rate (btu/kWh)	9,216	7,012	8,464	5,000	0	0	0	0	0	0	0	0	11,000	–	11,408	0
Fixed O&M ($/kW)	23.11	11.63	9.37	0.00	26.60	26.60	26.60	26.60	26.60	10.24	10.23	48.19	153.46	–	46.09	81.85
Var O&M ($/MWh)	2.98	1.90	0.10	9.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	–	1.59	0.00
Typical capacity factor	87.00%	57.00%	30.00%	91.00%	32.00%	34.00%	38.00%	44.00%	39.00%	30.00%	20.00%	37.00%	91.00%	–	82.00%	95.00%
Annual Generation (MWh)	3,048,480	1,248,300	262,800	398,580	420,480	446,760	499,320	578,160	512,460	2,628	4	162,060	39,858	–	2,873,280	416,100
Annual Fuel Consumption (mmbtu)	28,095,819	8,753,569	2,224,309	1,992,900	0	0	0	0	0	0	0	0	438,438	–	32,778,378	0
Emission Rates																
SO_2 (lb/MWh)	0.505	0.006	0.007	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.022	–	1.811	0.000
NO_x (lb/MWh)	0.991	0.199	0.677	0.100	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	4.103	–	3.656	0.000
CO_2 (lb/MWh)	1785.264	832.273	990.274	585.019	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	–	2076.795	0.000
Cost of Energy																
O&M (cents/kWh)	0.60	0.42	0.37	0.92	0.95	0.89	0.80	0.69	0.78	0.39	0.58	1.49	1.93	–	0.80	0.98
Fuel (cents/kWh)	0.87	3.35	4.05	2.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	–	0.74	0.00
Capital (cents/kWh)	2.83	1.43	1.99	1.45	4.15	3.91	3.50	3.02	3.41	22.87	53.97	20.01	2.65	–	0.55	4.10
Total (cents/kWh)	**4.30**	**5.20**	**6.41**	**4.76**	**5.10**	**4.80**	**4.29**	**3.71**	**4.18**	**23.26**	**54.55**	**21.50**	**4.58**	**–**	**2.10**	**5.08**

Dash indicates new units not deployed in time period indicated.

* CHP capital costs, emissions, and heat rates are incremental values in addition to boiler or hot water facility costs or characteristics.

† Wind costs do not include federal production tax credit.

‡ Carbon dioxide emissions for biomass combined-cycle unit and landfill gas unit are net emissions, relative to emissions from alternative use of biomass or landfill gas.

§ Capital cost pertains to adding co-firing capability to existing coal units. Co-firing data pertain to specific existing plants in Colorado and Montana, some of which have very low coal costs.

Fig. A-3. Cost and Performance Assumptions for New Generating Facilities Installed 2015–2020 (2000 dollars)

	Coal	Natural Gas			Wind †					Solar			Biomass			Geothermal
	Pulverized	Combined Cycle	Combustion Turbine	CHP*	Class 4	Class 5	Class 6	Class 7	BEP Average Wind Resource	Central PV	Rooftop PV	Solar Thermal	Landfill Gas ‡	Combined Cycle ‡	Co-firing in Existing Coal Plant §	
Design and Construction																
Typical plant size (MW)	400	250	100	50	150	150	150	150	150	1	0.002	50	5	100	400	50
Overnight capital cost ($/kW)	1,068	443	329	730	870	870	870	870	870	4,550	5,302	4,550	1,399	1,569	200	2,171
Capital Recovery Factor	19.90%	15.90%	15.70%	15.80%	12.80%	12.80%	12.80%	12.80%	12.80%	12.60%	12.60%	13.60%	15.10%	15.10%	19.90%	15.10%
Operation																
Fuel cost ($/mmbtu)	0.91	4.93	4.93	4.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.07	0.64	0.00
Heat rate (btu/kWh)	9,134	7,000	8,406	5,000	0	0	0	0	0	0	0	0	11,000	8,921	11,409	0
Fixed O&M ($/kW)	23.66	11.80	9.37	0.00	26.60	26.60	26.60	26.60	26.60	10.24	10.23	48.19	153.46	46.04	46.09	81.85
Var O&M ($/MWh)	3.29	1.78	0.10	9.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.07	1.59	0.00
Typical capacity factor	87.00%	57.00%	30.00%	91.00%	32.00%	34.00%	38.00%	44.00%	39.00%	30.00%	20.00%	37.00%	91.00%	81.00%	82.00%	95.00%
Annual Generation (MWh)	3,048,480	1,248,300	262,800	398,580	420,480	446,760	499,320	578,160	512,460	2,628	4	162,060	39,858	709,560	2,873,280	416,100
Annual Fuel Consumption (mmbtu)	27,844,380	8,738,236	2,209,133	1,992,900	0	0	0	0	0	0	0	0	438,438	6,329,675	32,781,252	0
Emission Rates																
SO_2 (lb/MWh)	0.427	0.006	0.008	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.022	0.000	1.813	0.000
NO_x (lb/MWh)	0.997	0.195	0.672	0.100	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	4.103	0.268	3.656	0.000
CO_2 (lb/MWh)	1747.050	829.925	983.518	585.098	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2077.126	0.000
Cost of Energy																
O&M (cents/kWh)	0.64	0.41	0.37	0.92	0.95	0.89	0.80	0.69	0.78	0.39	0.58	1.49	1.93	0.96	0.80	0.98
Fuel (cents/kWh)	0.83	3.45	4.14	2.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.74	0.72	0.00
Capital (cents/kWh)	2.79	1.41	1.97	1.45	3.97	3.74	3.35	2.89	3.26	21.82	38.13	19.09	2.65	3.34	0.55	3.94
Total (cents/kWh)	**4.25**	**5.27**	**6.47**	**4.83**	**4.92**	**4.63**	**4.14**	**3.58**	**4.04**	**22.20**	**38.71**	**20.58**	**4.58**	**7.03**	**2.08**	**4.92**

Dash indicates new units not deployed in time period indicated.

* CHP capital costs, emissions, and heat rates are incremental values in addition to boiler or hot water facility costs or characteristics.

† Wind costs do not include federal production tax credit.

‡ Carbon dioxide emissions for biomass combined-cycle unit and landfill gas unit are net emissions, relative to emissions from alternative use of biomass or landfill gas.

§ Capital cost pertains to adding co-firing capability to existing coal units. Co-firing data pertain to specific existing plants in Colorado and Montana, some of which have very low coal costs.

Appendix B Determination of Transmission and Distribution Costs

PROSYM divides the western electric grid into a number of interlinked transmission areas (trans areas), designed to capture the transmission capabilities between sub-regions in the West. In our analysis, there are 10 transmission areas in the seven-state study region and 22 within the entire western grid. Figure B-1 shows the trans areas used in the analysis.

We included four categories of transmission and distribution (T&D) costs in the analysis:

- Load-driven T&D costs based on information from the Energy Information Administration's National Energy Modeling System (NEMS)
- Inter-trans area transmission costs to move power between trans areas
- Intra-trans area transmission costs to move wind generation within trans areas
- Wind-to-grid transmission costs to move wind generation to the transmission grid

Each of these cost categories is described in more detail below. Our approach was designed to ensure that there was sufficient transmission capacity to transport generation from the sources to the loads under both Business as Usual and the Balanced Energy Plan. It does not optimize the transmission system. There may be places where we overbuild transmission lines, and there may be lower-cost opportunities for relocating either transmission enhancements or new power plants in order to minimize the combined costs.

Load-driven T&D costs based on NEMS information

As a starting point for estimating transmission and distribution costs we assumed that additional transmission capacity would be needed as demand increases. At the trans area

Fig. B-1. Transmission and Distribution Cost Assumptions (2000 dollars)

	Transmission Average Cost cents/kWh				Distribution Average Cost cents/kWh			
	Rocky Mountain Area (AZ, CO, NM, Southern NV)		Northwest Power Pool (MT, UT, WY, Northern NV)		Rocky Mountain Area (AZ, CO, NM, Southern NV)		Northwest Power Pool (MT, UT, WY, Northern NV)	
Year	Business as Usual	Balanced Energy Plan	Business as Usual	Balanced Energy Plan	Business as Usual	Balanced Energy Plan	Business as Usual	Balanced Energy Plan
2002	0.7	0.7	0.8	0.8	2.0	2.0	1.5	1.5
2008	1.0	1.0	0.9	0.9	2.0	2.2	1.5	1.6
2014	1.0	0.9	1.0	0.9	2.0	2.2	1.4	1.6
2020	1.0	1.0	1.0	0.8	2.0	2.2	1.4	1.6

level used in PROSYM there is not sufficient detail to look at specific transmission lines or distribution systems. As a result, we developed average T&D capacity costs in dollars per kWh. These average costs were determined by analyzing the T&D cost information contained in the NEMS model using *Annual Energy Outlook 2002* assumptions. We then multiplied these average T&D costs by annual electric load in the BAU and Balanced Energy Plan scenarios to estimate annual transmission and distribution costs under each scenario. Figure B-1 shows the load-driven cost assumptions used in the analysis.

Inter-trans areas costs

Our scenarios deviate from those of the NEMS models used in the *Annual Energy Outlook 2002* with regard to the location, timing, amount and type of generating capacity installed, especially in the Balanced Energy Plan. Our BEP scenario also deviated from NEMS with regard to the growth of electricity demand. Consequently, some of the regions within our study may require additional transmission capacity in order to move electricity from the new generator sources to the load centers. Such new transmission might be especially important to transmit wind power, because new wind resources tend to be located in relatively remote locations.

This additional transmission capacity is assumed to be needed both between transmission areas (referred to as inter-trans areas) and within transmission areas (referred to as intra-trans areas and discussed below). We used the transmission loading capabilities of the PROSYM model to identify regions where the inter-trans area transmission capacity might need to be enhanced in order to support the new generation in our scenarios.

Again, we did not have the capability to model transmission loadings in great detail, so we developed a rule of thumb to determine when new transmission capacity between transmission areas would be needed in future years. The PROSYM model provides information about transmission capacities and loadings between transmission areas in the West. For future years, we applied a rule of thumb that if a transmission path between transmission areas was loaded to at least 50 percent of its capacity for at least 75 percent of the time, an upgrade would be needed. We reviewed recent transmission loadings in the West and found that transmission paths meeting our rule of thumb had load factors of 65 percent or greater. Thus, we added transmission capacity between transmission areas when paths exhibited average load factors above 65 percent.

In determining how much to upgrade the transmission for each case, we first looked at the line loadings in 2020 with all of our assumed resource additions and no unplanned transmission additions. We then re-ran the scenario with an estimation of unplanned transmission upgrades, increasing the capacity of those paths that were heavily loaded. We repeated this process until we had adequate transmission upgrades for each case.

We focused on transmission needs in 2020, but where there was a need for transmission enhancements in earlier years we phased in the new transmission enhancements linearly over our study period. Also, if a path is heavily loaded in one of our study years but falls below the 65 percent threshold in a later study year due to the addition of new power plants, then we assume that this path does not require upgrading. We assumed an annual cost of $64 per MW-mile for inter-trans area transmission costs (in 2000 dollars). This figure is meant to represent the costs on enhancing or expanding existing transmission lines, as opposed to all the costs of building new transmission lines through new rights-of-way.

Intra-trans areas wind transmission costs

PROSYM does not provide an indication of the extent to which transmission lines are available or loaded within a transmission area. In general, we assumed that these intra-trans area transmission costs would be captured by the per kWh average transmission costs coming out of the NEMS model. We also assumed that there would be additional transmission enhancements necessary within trans areas in order to move new wind power from remote windy locations throughout each trans area.

Thus, the intra-trans area costs pertain to transmission upgrades needed to move wind-generated electricity to load centers within the trans area or to the edge of the transmission area where it can be exported to load centers in other trans areas. We made some rough assumptions to capture these potential costs. For each state we estimated the distance that the wind generation must be transmitted, and multiplied this distance by the cost of transmission in $/MW-mile. The transmission mileage is roughly estimated by taking account of several factors, including:

- The number of transmission areas per state. More transmission areas suggest less mileage.
- The size of each state. Larger states suggest more mileage.
- The extent to which there is load in each transmission area within each state. Larger loads suggest less mileage.
- The likelihood that the wind generation will be exported out of the transmission areas in each state. More exports suggest more mileage.

For each state we estimated the intra-trans area mileage by multiplying the maximum distance across a state by a scaling factor. These assumptions are summarized in Figure B-2 below.

Fig. B-2. Estimated Transmission Mileage by State

State	Distance Across State	Scaling Factor	Transmission Mileage
Arizona	293	10%	29
Colorado	400	30%	120
Montana	630	50%	315
Nevada	385	40%	154
New Mexico	518	10%	52
Utah	435	50%	218
Wyoming	450	50%	225

The intra-trans area scaling factor and thus transmission mileage for each state is assumed to be the same in both the BAU and Balanced Energy Plan scenarios. However, the intra-trans area transmission costs will vary between the scenarios, because the amount of wind capacity in each state varies between the scenarios. We assumed an annual cost of $64 per MW-mile for intra-trans area wind transmission costs (in 2000 dollars).

Wind-to-grid transmission costs

Wind-to-grid costs are those required to connect the wind farm to the nearest point on the electric grid. The costs are based on assumptions used in the NEMS model. NEMS includes costs for three different distances: 0 to 5 miles, 5 to 10 miles, and 10 to 20 miles.

For each state we assessed the extent to which we are tapping into the potential wind resource. In Arizona and New Mexico – where we tap into most, or all, of the potential resource – we assumed that on average the wind turbines will be located roughly 10 to 20 miles from the grid. For all other states – where we are tapping into only a small portion of the total wind potential – we assumed that on average the wind turbines will be located roughly 0 to 5 miles from the grid. These assumptions are based on a GIS analysis of the existing transmission lines in the seven-state study area and the potential wind resources from the *Renewable Energy Atlas of the West.*

Based on the NEMS assumptions, we assumed the 0-to-5 mile interconnection will cost \$12/kW in the northwest states (MT, WY, northern NV, UT) and \$9/kW in the Rocky Mountain area (AZ, CO, NM, southern NV). For the 10-to-20 mile interconnection the cost was assumed to be \$70/kW in the northwest states and \$51/kW in the Rocky Mountain area.

Transmission and distribution cost summary

Figure B-3 summarizes transmission and distribution costs by category for the BAU scenario and the Balanced Energy Plan.

Fig. B-3. Annual Transmission and Distribution Costs by Category (thousands of 2000 dollars)

	Business as Usual				Balanced Energy Plan			
	2002	**2008**	**2014**	**2020**	**2002**	**2008**	**2014**	**2020**
Transmission								
Load-driven (NEMS)	1,458,032	2,451,607	2,818,469	3,217,623	1,458,032	2,175,774	1,982,722	2,235,984
Inter-Trans Area	0	68,042	87,391	106,771	0	77,330	105,964	134,631
Intra-Trans Area Wind	0	2,802	4,366	5,651	0	31,333	60,785	90,207
Wind-to-Grid	0	486	625	811	0	7,498	13,594	19,669
Total Transmission	**1,458,032**	**2,522,937**	**2,910,852**	**3,330,856**	**1,458,032**	**2,291,935**	**2,163,064**	**2,480,490**
Distribution								
Load-driven (NEMS)	4,165,805	4,903,215	5,636,939	6,435,246	4,165,805	4,786,703	4,846,653	4,919,164
Total T&D	**5,623,837**	**7,426,152**	**8,547,791**	**9,766,102**	**5,623,837**	**7,078,638**	**7,009,717**	**7,399,654**

Note: Figures rounded to nearest thousand dollars. Columns may not sum due to rounding.

Appendix C Balanced Energy Plan Capacity and Generation

Fig. C-1. Balanced Energy Plan Electric Generating Capacity (MW)

	Capacity				Net Additions
Resource	**2002**	**2008**	**2014**	**2020**	**2003–2020**
Coal	28,750	26,225	24,720	23,940	-4,810
Natural Gas *	13,110	20,155	19,485	17,680	4,575
CHP	945	1,910	3,115	4,080	3,135
Hydro	5,010	5,010	5,010	5,010	-5
Nuclear	3,790	3,790	3,790	3,790	0
Renewables					
Wind	235	3,450	6,260	9,065	8,835
Geothermal	295	1,255	2,180	2,380	2,085
Solar					
Central PV	5	545	1,080	1,620	1,610
Rooftop PV	0	60	235	995	995
Solar Thermal	0	290	580	870	870
Total Solar	5	890	1,900	3,485	3,480
Biomass					
Biomass †	45	45	45	45	0
Landfill Gas	5	120	120	120	115
Combined-cycle	0	0	0	425	425
Co-firing	0	0	475	475	475
Total Biomass	55	170	645	1,070	1,015
Total Renewables	585	5,765	10,980	16,000	15,410
Other ‡	1,855	1,885	1,890	1,880	25
Total	**54,045**	**64,735**	**68,995**	**72,385**	**18,335**

Note: Figures rounded to nearest 5 MW. Rows and columns may not sum due to rounding.

* Includes combined-cycle, combustion turbine and steam natural gas units.
† Existing dedicated biomass facilities primarily burning wood wastes.
‡ Includes oil, pumped storage and other miscellaneous resources.

Fig. C-2. Balanced Energy Plan Generation by Resource: Base Case Conditions

	Generation by Resource Type (GWh)				Percent of Total Generation			
Resource	**2002**	**2008**	**2014**	**2020**	**2002**	**2008**	**2014**	**2020**
Coal	201,073	181,212	164,453	150,622	68.4%	57.4%	51.5%	46.6%
Natural Gas								
Conventional Natural Gas*	34,029	48,068	36,631	29,123	11.6%	15.2%	11.5%	9.0%
CHP	5,260	11,110	20,614	28,303	1.8%	3.5%	6.5%	8.8%
Total Natural Gas	39,288	59,178	57,245	57,426	13.4%	18.7%	17.9%	17.8%
Nuclear	28,483	28,437	27,942	27,267	9.7%	9.0%	8.7%	8.4%
Hydro	19,520	19,500	19,507	19,507	6.6%	6.2%	6.1%	6.0%
Renewables	3,470	25,669	48,585	66,336	1.2%	8.1%	15.2%	20.5%
Other †	2,032	1,848	1,763	1,726	0.7%	0.6%	0.6%	0.5%
Total	**293,866**	**315,844**	**319,496**	**322,884**	**100%**	**100%**	**100%**	**100%**

Note: Figures rounded to the nearest GWh. Columns may not sum due to rounding.

* Includes combined-cycle, combustion turbine and steam natural gas units.

† Includes oil, pumped storage and other miscellaneous resources.

Fig. C-3. Balanced Energy Plan Renewable Energy Generation by Resource: Base Case Conditions

	Renewable Generation by Resource Type (GWh)				Percent of Renewable Generation				Percent of Total Generation			
Resource	**2002**	**2008**	**2014**	**2020**	**2002**	**2008**	**2014**	**2020**	**2002**	**2008**	**2014**	**2020**
Wind	613	11,436	21,083	30,704	17.7%	44.6%	43.4%	46.3%	0.2%	3.6%	6.6%	9.5%
Geothermal	2,394	10,415	17,613	19,072	69.0%	40.6%	36.3%	28.8%	0.8%	3.3%	5.5%	5.9%
Solar												
Solar PV Central	32	1,443	2,855	4,267	0.9%	5.6%	5.9%	6.4%	0.0%	0.5%	0.9%	1.3%
Solar PV Rooftop	0	102	416	1,746	0.0%	0.4%	0.9%	2.6%	0.0%	0.0%	0.1%	0.5%
Solar Thermal	0	939	1,879	2,818	0.0%	3.7%	3.9%	4.2%	0.0%	0.3%	0.6%	0.9%
Total Solar	32	2,485	5,150	8,832	0.9%	9.7%	10.6%	13.3%	0.0%	0.8%	1.6%	2.7%
Biomass												
Biomass	377	374	368	358	10.9%	1.5%	0.8%	0.5%	0.1%	0.1%	0.1%	0.1%
Landfill Gas	56	960	960	959	1.6%	3.7%	2.0%	1.4%	0.0%	0.3%	0.3%	0.3%
Combined-Cycle	0	0	0	3,007	0.0%	0.0%	0.0%	4.5%	0.0%	0.0%	0.0%	0.9%
Co-firing	0	0	3,412	3,404	0.0%	0.0%	7.0%	5.1%	0.0%	0.0%	1.1%	1.1%
Total Biomass	432	1,334	4,739	7,728	12.5%	5.2%	9.8%	11.7%	0.1%	0.4%	1.5%	2.4%
Total	**3,470**	**25,669**	**48,585**	**66,336**	**100%**	**100%**	**100%**	**100%**	**1.2%**	**8.1%**	**15.2%**	**20.5%**

Note: Figures rounded to the nearest GWh. Columns may not sum due to rounding.

Appendix D Business as Usual Capacity and Generation

Fig. D-1. Business as Usual Electric Generating Capacity (MW)

	Capacity				Net Additions
Resource	**2002**	**2008**	**2014**	**2020**	**2003–2020**
Coal	28,750	30,415	31,880	38,115	9,365
Conventional Natural Gas *	13,110	24,925	26,140	27,220	14,115
CHP	945	1,090	1,090	1,090	150
Hydro	5,010	5,010	5,010	5,010	-5
Nuclear	3,790	3,790	3,790	3,790	0
Renewables					
Wind	235	710	805	960	725
Geothermal	295	710	820	905	610
Solar					
Central PV	5	55	70	75	70
Rooftop PV	0	0	0	0	0
Solar Thermal	0	55	110	115	115
Total Solar	5	110	180	195	185
Biomass					
Biomass †	45	45	45	45	0
Landfill Gas	5	15	15	15	5
Combined-cycle	0	0	0	0	0
Co-firing	0	0	0	0	0
Total Biomass	55	60	60	60	5
Total Renewables	585	1,590	1,870	2,120	1,530
Other ‡	1,855	1,885	1,890	1,880	25
Total	**54,045**	**68,705**	**71,675**	**79,230**	**25,180**

Note: Figures rounded to nearest 5 MW. Rows and columns may not sum due to rounding.

* Includes combined-cycle, combustion turbine and steam natural gas units.

† Existing dedicated biomass facilities primarily burning wood wastes.

‡ Includes oil, pumped storage and other miscellaneous resources.

Fig. D-2. Business as Usual Generation by Resource: Base Case Conditions

	Generation by Resource Type (GWh)				Percent of Total Generation			
Resource	**2002**	**2008**	**2014**	**2020**	**2002**	**2008**	**2014**	**2020**
Coal	201,073	216,476	229,850	277,664	68.4%	61.8%	59.6%	63.7%
Natural Gas								
Conventional Natural Gas*	34,029	71,107	91,335	92,735	11.6%	20.3%	23.7%	21.3%
CHP	5,260	4,208	4,092	3,525	1.8%	1.2%	1.1%	0.8%
Total Natural Gas	39,288	75,315	95,427	96,260	13.4%	21.5%	24.8%	22.1%
Nuclear	28,483	28,437	28,398	28,455	9.7%	8.1%	7.4%	6.5%
Hydro	19,520	19,500	19,508	19,508	6.6%	5.6%	5.1%	4.5%
Renewables	3,470	8,737	10,249	11,589	1.2%	2.5%	2.7%	2.7%
Other †	2,032	1,858	2,077	2,129	0.7%	0.5%	0.5%	0.5%
Total	**293,866**	**350,323**	**385,509**	**435,604**	**100%**	**100%**	**100%**	**100%**

Note: Figures rounded to the nearest GWh. Columns may not sum due to rounding.

* Includes combined-cycle, combustion turbine and steam natural gas units.

† Includes oil, pumped storage and other miscellaneous resources.

Fig. D-3. Business as Usual Renewable Energy Generation by Resource: Base Case Conditions

	Renewable Generation by Resource Type (GWh)				Percent of Renewable Generation				Percent of Total Generation			
Resource	**2002**	**2008**	**2014**	**2020**	**2002**	**2008**	**2014**	**2020**	**2002**	**2008**	**2014**	**2020**
Wind	613	2,044	2,421	3,013	17.7%	23.4%	23.6%	26.0%	0.2%	0.6%	0.6%	0.7%
Geothermal	2,394	5,868	6,786	7,495	69.0%	67.2%	66.2%	64.7%	0.8%	1.7%	1.8%	1.7%
Solar												
Central PV	32	157	194	217	0.9%	1.8%	1.9%	1.9%	0.0%	0.0%	0.1%	0.0%
Rooftop PV	0	0	0	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar Thermal	0	181	360	376	0.0%	2.1%	3.5%	3.2%	0.0%	0.1%	0.1%	0.1%
Total Solar	32	338	554	593	0.9%	3.9%	5.4%	5.1%	0.0%	0.1%	0.1%	0.1%
Biomass												
Biomass	377	376	377	377	10.9%	4.3%	3.7%	3.2%	0.1%	0.1%	0.1%	0.1%
Landfill Gas	56	111	111	111	1.6%	1.3%	1.1%	1.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	0	0	0	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Co-firing	0	0	0	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Biomass	432	487	488	488	12.5%	5.6%	4.8%	4.2%	0.1%	0.1%	0.1%	0.1%
Total	**3,470**	**8,737**	**10,249**	**11,589**	**100%**	**100%**	**100%**	**100%**	**1.2%**	**2.5%**	**2.7%**	**2.7%**

Note: Figures rounded to the nearest GWh. Columns may not sum due to rounding.

Appendix E An Alternative Strategy for Reducing Natural Gas Price and Carbon Risk

One of the important benefits of the Balanced Energy Plan is that it hedges against the risk of higher electricity costs due to rising natural gas prices and the possibility of future carbon dioxide regulations. This is accomplished by relying on large investments in energy efficiency and renewable energy, which do not use natural gas or emit carbon dioxide, as well as combined heat and power resources, which use natural gas more efficiently and emit less carbon dioxide per kilowatt-hour of electricity produced than conventional fossil fuel power plants.

As noted, we acknowledge that there are risks in the Balanced Energy Plan. For example, achieving the high levels of energy efficiency included in the BEP will be challenging. It will require concerted, long-term, successful policies and actions on the part of governments, utilities, manufacturers, and customers to overcome barriers to efficiency, and there is uncertainty about whether all the necessary policies and actions will be undertaken. Furthermore, the region's commercial and industrial electricity users may not adopt combined heat and power at the levels laid out in the BEP. The Balanced Energy Plan's renewable energy component may be less difficult to implement because of some favorable factors – the declining costs of renewables, the region's abundant supply of renewable resources, and increasing interest in renewable energy by major corporations (General Electric and Shell, for example), as well as evolving state government policies on the role of renewable energy.

Given these uncertainties, we developed an Alternative Plan that relies less heavily on energy efficiency and combined heat and power technologies but has roughly the same carbon dioxide emission and natural gas consumption profile. To do this we replaced the efficiency and CHP resources with integrated gasification combined-cycle (IGCC) coal plants as well as some additional wind power. The objective was to create an alternative scenario that, like the Balanced Energy Plan, would also act as a hedge against natural gas and carbon risk.

Below we describe the features of the Alternative Plan and how it compares to both Business as Usual and the Balanced Energy Plan.

Source: DOE/NETL

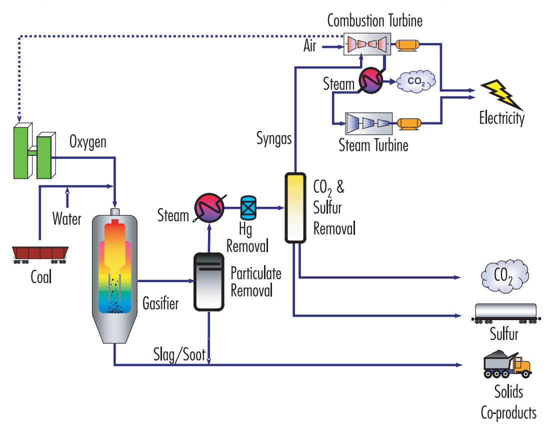
Wabash River coal gasification repowering project, Indiana

What is IGCC?

Integrated gasification combined-cycle is a technology for producing electricity from coal. In this regard, IGCC is similar to a conventional coal power plant. However, unlike a conventional coal plant, the first step in the IGCC process involves gasification of the coal. The gasification process breaks down the coal into its basic chemical constituents and creates synthetic gas ("syngas"). Once the syngas is produced, hydrogen sulfide, particulate matter, and other pollutants can be removed.

The cleaned syngas is combusted in a combined-cycle gas turbine to produce electricity. The syngas production process and the gas turbine combustion process both generate heat that is used to produce steam, which in turn is used to generate electricity. Thus, IGCC technology produces electricity through a combination of a gas turbine and a steam turbine (see diagram below).

Integrated Gasification Combined Cycle (IGCC) Configuration



Source: Eastman Gasification Services Company 2003.

Two full-scale commercial IGCC generating units are in operation in the U.S. – Tampa Electric Company's 262 MW unit at the Polk plant in Florida and Cinergy's 192 MW unit at the Wabash River plant in Indiana. Worldwide there are 131 gasification projects in operation with a combined capacity equivalent to 23,750 MW of IGCC units, although not all of these projects produce electricity from coal.[1]

Although there are IGCC facilities currently in operation, most utilities still consider IGCC an immature technology subject to performance risks. In recognition of this, over 75 percent of the IGCC capacity in the Alternative Plan is added to the system after 2009.

One of the principal advantages of IGCC power plants is that they can be configured to capture carbon dioxide emissions at a much lower cost than at either natural gas or conventional coal power plants. The reason lies in the high concentration of CO_2 – between 35 and 40 percent – in the flue gas stream from the gasifier. In contrast, the CO_2 concentration in flue gas from a conventional coal plant is about 15 percent and only about 4 percent for natural gas plants. The higher the concentration, the more cost-effective it is to capture CO_2. IGCC plants also have lower emissions of sulfur dioxide, nitrogen oxides, mercury and particulates than conventional coal plants, even when conventional plants are equipped with state-of-the-art pollution controls.

Given these characteristics, IGCC technologies can reduce the region's exposure to the risk of future regulations on carbon dioxide, as well as other air quality regulations. In addition, ICGG plants are not subject to the risk of rising natural gas prices.

Currently the capital costs for an IGCC facility are 20 to 25 percent higher than for a conventional coal power plant, not including CO_2 capture equipment.[2] The IGCC capital and operating cost assumptions used in our analysis result in a cost of energy of roughly 6.8 cents per kWh, including carbon dioxide capture, transportation and storage costs. Figure E-1 summarizes the cost and performance characteristics of IGCC plants.

1 Simbeck, Dale, SFA Pacific Inc. Gasification Technology Update, presented to the European Gasification Conference, April 8-10, 2002. The total capacity is based on output of synthesis gas. Many of these projects produce chemicals in addition to or instead of electricity.

2 Rosenberg, W., D. Alpern and M. Walker. 2004. *Financing IGCC – 3Party Convenant.* BSCIA Working Paper 2004-01, Energy Technology Innovation Project, Belfer Center for Science and International Affairs.

Fig. E-1. Cost and Performance Assumptions for IGCC Coal Facilities Installed 2009–2014 (costs in 2000 dollars)

	IGCC with CO2 removal *
Design and Construction	
Plant size (MW)	400
Overnight capital cost ($/kW)	1,287
Capital Recovery Factor	18.8%
Operation	
Fuel cost ($/mmbtu)	0.95
Heat rate (btu/kWh)	8,462
Fixed O&M ($/kW)	34.86
Var O&M ($/MWh)	22.61
Assumed capacity factor	85%
Annual Generation (MWh)	2,978,400
Annual Fuel Consumption (mmbtu)	25,203,295
Emission Rates	
SO_2 (lb/MWh)	0.072
NO_x (lb/MWh)	0.423
CO_2 (lb/MWh)	173.472
Cost of Energy	
O&M (cents/kWh)	2.73
Fuel (cents/kWh)	0.80
Capital (cents/kWh)	3.25
Total (cents/kWh)	**6.78**

* Costs of carbon dioxide capture, transportation, and injection costs are included in O&M costs. CO_2 capture, transportation, and injection costs based on: David, J. and H. Herzog. *The Cost of Carbon Capture.* 5th International Conference on Greenhouse Gas Control. Cairns, Queensland, Australia. August 14–16, 2000.

Compared to the Balanced Energy Plan, the Alternative Plan has the following features:

- Reduced energy savings from efficiency. Under the Alternative Plan, energy efficiency savings are two-thirds of the savings achieved under the Balanced Energy Plan. For the seven Interior West states, load growth from 2002 to 2020 is thus assumed to be at a compound annual growth rate of 1.2 percent instead of 0.4 percent as assumed in the BEP. Expected load growth under the Alternative Plan is shown in Figure E-2, which also shows the BAU case and the Balanced Energy Plan for comparison.
- Reduced electricity generation from combined heat and power resources. Under the Alternative Plan, CHP generation in 2020 is about 69 percent of that in the BEP.
- Increased generation from renewable resources. Renewable energy accounts for about 24 percent of electricity generation in the Alternative Plan in 2020 and about 20 percent under the Balanced Energy Plan. The increased generation is due to deployment of additional wind facilities.
- Deployment of about 3750 MW of new integrated gasification combined-cycle coal plants by 2020.

Fig. E-2. Electric Load Growth in the Interior West

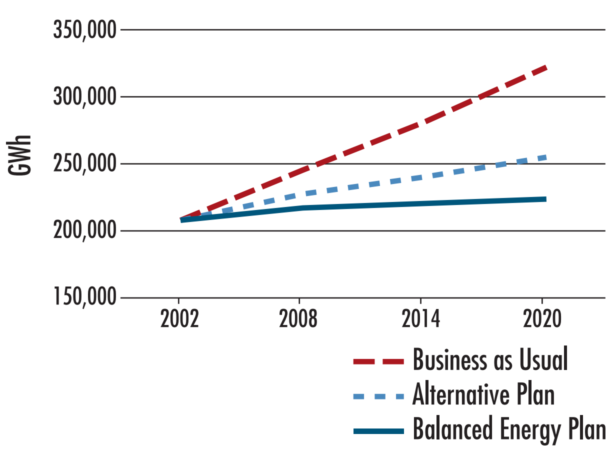


Figure E-3 compares the generation mix in 2020 for the BAU case, the Alternative Plan and the Balanced Energy Plan.

Figure E-4 compares cost components for the three scenarios for the year 2020. The Alternative Plan has the highest capital costs for new generating capacity because of its increased reliance on wind power and IGCC technology. It does not attain the savings in production costs and transmission and distribution costs found in the Balanced Energy Plan because of less reliance on energy efficiency, but it also does not incur as much cost for energy efficiency measures as the BEP does.

Under base case conditions, the annual costs of the Alternative Plan are higher than Business as Usual for each of the years 2008, 2014 and 2020. Thus the Alternative Plan does not save the region money over the study period as the Balanced Energy Plan does (Figure E-5).

Fig. E-3. Interior West Generation Mix in 2020

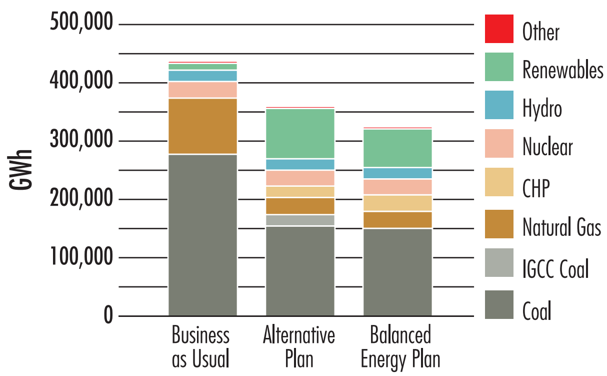


Fig. E-4. Cost Components in 2020

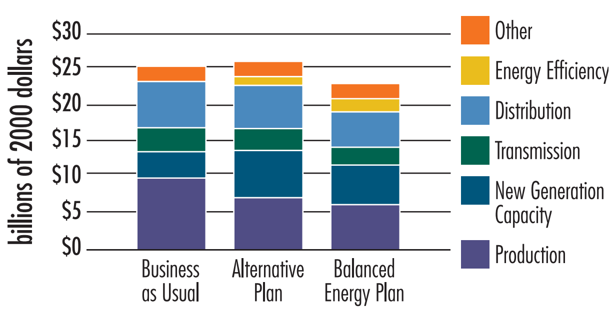
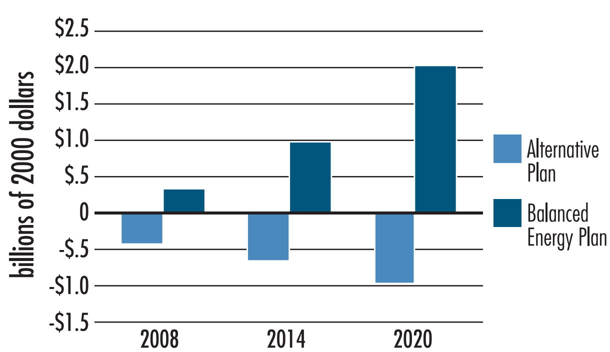


Fig. E-5. Savings Relative to Business as Usual: Alternative Plan and Balanced Energy Plan



In addition, relative to Business as Usual, the Alternative Plan does not perform as well as the Balanced Energy Plan under the risk scenarios, although it does hedge against costs of potential carbon dioxide regulation (Figures E-6 and E-7).

Because of the high level of emission control possible at IGCC plants, the Alternative Plan achieves reductions in sulfur dioxide, nitrogen oxide, and carbon dioxide emissions comparable to levels achieved under the Balanced Energy Plan. Figure E-8 shows changes in these emissions from 2002 to 2020 under the three scenarios.

In sum, under base case conditions the Alternative Plan is more expensive than both the Balanced Energy Plan and BAU. In 2020, the Alternative Plan costs $1.0 billion more than BAU and $3.0 billion more than the Balanced Energy Plan. The Alternative Plan, however, does provide environmental and carbon risk mitigation benefits that, while not as robust as those of the Balanced Energy Plan, are significantly better than BAU.

Relative to Business as Usual, the Alternative Plan saves the region $1.9 billion in 2020 under the carbon risk scenario. This compares to $4.9 billion of savings that occur in the Balanced Energy Plan by 2020 under the carbon risk scenario. Thus, while the Alternative Plan would help protect the region from the risks of future carbon regulations, it does so at higher cost than the Balanced Energy Plan, which relies more heavily on energy efficiency and combined heat and power.

Fig. E-6. Risk Scenarios: Balanced Energy Plan Savings Relative to Business as Usual

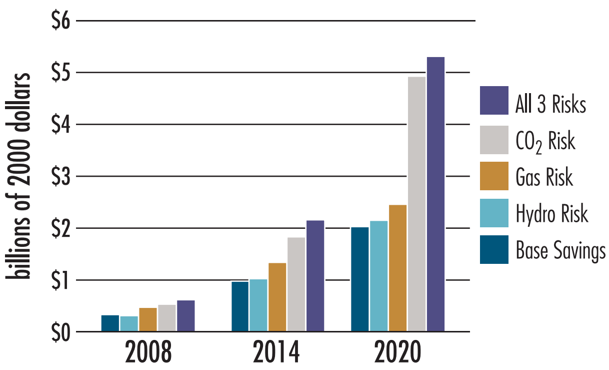


Fig. E-7. Risk Scenarios: Alternative Plan Savings Relative to Business as Usual

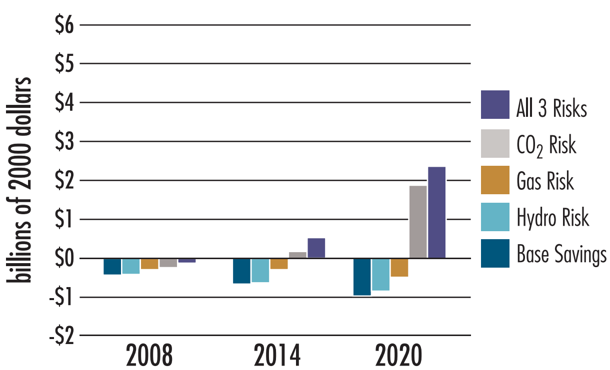
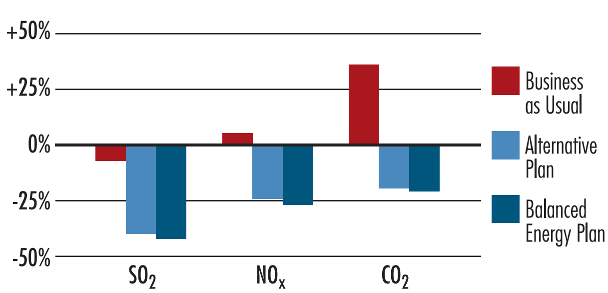


Fig. E-8. Percentage Change in Air Emissions from 2002 to 2020



Glossary

Acre-foot	the volume of water required to cover one acre of land to a depth of one foot; equal to 325,851 gallons.
Cap-and-trade programs	incentive-based environmental programs in which a regulatory agency specifies a cap on the total level of pollution that will be allowed by a group of sources such as power plants and then allocates this amount among individual sources by issuing emission permits. Owners of the permits may hold them and release pollutants, or reduce their emissions and sell the permits to other sources.
Capacity	the amount of electric power which a generator can produce or a transmission system can deliver.
Combined heat and power	simultaneous production of heat energy and electricity from the same fuel in the same facility.
Energy efficiency	technologies and practices that reduce energy use without reducing the level or quality of electric services.
Greenhouse gases	gases such as carbon dioxide and methane that trap heat within the Earth's atmosphere.
Grid	the network of power lines and associated equipment required to deliver electricity from generating facilities to consumers.
Levelized cost	the total lifetime cost of electricity production from a generating facility (including fuel costs, operating and maintenance costs, and capital costs) distributed uniformly over the expected life of the facility using present value arithmetic. Levelized costs are most frequently presented as a cost per kWh of electricity production.
Load	amount of electricity demanded by consumers at any given time.
Marginal costs	the additional costs incurred by producing one more unit of output.
Marginal resource	the last electric generating resource brought on-line to meet demand at any given time.

Energy Units

Watt	a unit of electrical power
Kilowatt (kW)	one thousand watts
Kilowatt-hour (kWh)	a standard measure of electric energy, equivalent to a 100-watt light bulb burning for 10 hours
Megawatt (MW)	one million watts
Gigawatt (GW)	one billion watts
BTU (British Thermal Unit)	a standard unit for measuring heat energy; the amount of heat needed to raise the temperature of one pound of water by one degree Fahrenheit
MMBTU	one million BTUs