Public Service Company of Colorado

2011 Electric Resource Plan

Volume II Technical Appendix

(CPUC Docket No. 11A-)

October 31, 2011

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2.1 RESOURCE PLANNING BASICS

In its simplest form, electric resource planning is the process of taking forecasts of customer electric demand and energy and determining the appropriate electric generation units that should be used or developed to meet those customer requirements in a cost-effective and reliable fashion. Engineering, permitting and constructing electric generating facilities takes a significant amount of time and therefore the resource planning process must be completed with adequate lead time to allow the actual development of new resources that are needed in order to meet customer energy requirements.

Historically, resource planning in Colorado implemented a least-cost approach to meet growing demand. Changes in State and public policy resulted in a shift away from the least-cost approach toward resource plans that incorporate resources in a cost-effective manner. This shift allows greater consideration of clean energy resources.

The following discussion provides an overview of the resource planning process.

Definitions

1. Capacity is the instantaneous capability of an electrical system to provide electricity or energy to meet demand and is usually measured in megawatts ("MW").
2. Annual Capacity Factor is the ratio of the net energy produced by a generating facility over a defined period (year), to the amount of energy that could have been produced if the facility operated continuously at full capacity over the same period (year).
3. Capacity Rating (or Effective Load Carrying Capability) reflects the amount of Capacity that is expected to be available under reasonable conditions in the hour of the year/season in which the system demand is highest.
4. Energy is the rate of electrical power delivered over a quantity of time and is usually measured in megawatt hours ("MWh").
5. Demand or load is the level of power consumed at an instantaneous point in time.
6. Heat Rate defines the efficiency of the generation unit. Generally, heat rate is measured by units of fuel burned to create a MWh of energy.
7. Load Duration Curve is a representation of the hourly average demand data, sorted in a descending order and presented graphically over some period of time. The load duration curve's height (where it intersects the Y or left-side axis) represents the peak Demand or highest level of hourly energy usage for the time period and the height at the right side of the curve is the lowest Demand for the time period. The area under the curve of the load duration curve represents the amount of annual energy required for the time period. Load duration curves can be presented on a daily, monthly, or annual time periods, with annual being the most common.

8. Dispatchable Resource is a resource that provides the ability to physically control the generation output of that facility. Generally, these are thermal units that consume a fuel or storage type of units that can be "switched" on or off.
9. Non-Dispatchable Resource is a resource without the ability to physically control the generation output of that facility. Generally, renewable type resources that only produce electricity when fuel (wind or sunshine) is available or because a contract or purchased power agreement limits the way in which the unit output can be changed.
10. Reserve Margin or Planning Reserve Margin is the amount of additional generation capacity that a utility should or must plan to have available to meet contingencies, including but not limited to, higher than expected Demand, unplanned generation outages, and inoperable transmission infrastructure.
11. Economic dispatch is the process used to try to minimize the cost of generation committed and used to produce energy to meet Demand by considering the variable operating characteristics of a generating unit, including fuel cost, operating parameters, Heat Rate, and variable costs. Economic dispatch is looked at on a moment-to-moment basic as generation assets are deployed to meet actual customer loads but is simulated in generation dispatch computer models at a higher level to compare how different potential resources will impact customer costs.

The basic types of resources that are available for matching electricity supply and demand are discussed below. These resources play different roles in meeting a utility's demand and energy requirements. Supply-side resources provide generation capacity to serve load, whereas demand side resources act to reduce the level of customer demand for electric power so fewer supply side resources are required. Supply-side resources generally fall into two categories: traditional (or thermal) and renewable. Traditional supply-side resources are typically fossil fuel based generation resources with physical fuel supplies. In contrast, renewable resources are supply-side generation resources with essentially elemental fuel supplies.

Examples of Traditional Supply-Side Resources

1. Combustion Turbines ("CT") – These simple cycle, natural gas fired units are available in a wide range of sizes (25 MW to 300 MW). Combustion turbines are very similar to a jet engine with an electrical generator connected to the turbine shaft. Combustion turbines are typically inexpensive to build but are less efficient sources of generation. The ideal role for CTs is to be run for a few hours of the year typically at times of the highest electric demand
2. Combined Cycle ("CC") – These high efficiency, natural gas fired facilities use a single or multiple CTs in conjunction with a Heat Recovery Steam Generator ("HRSG"). The waste heat from CT's exhaust gas is used to generate steam to run a steam turbine which in turn produces additional electric power. Combined cycle units come in a variety of sizes near 100 MW to over 700 MW depending on the specific configuration of the facility. A

larger sized CC generally has lower per MW cost as a result of economies of scale. CC units have higher build costs than CT units, but lower operating costs.

3. Baseload – These units are designed to run continuously, i.e., all hours of the year except when shut down for planned maintenance. Baseload units have the highest cost to build but the lowest fuel costs. Typically baseload units use coal or nuclear fuel.

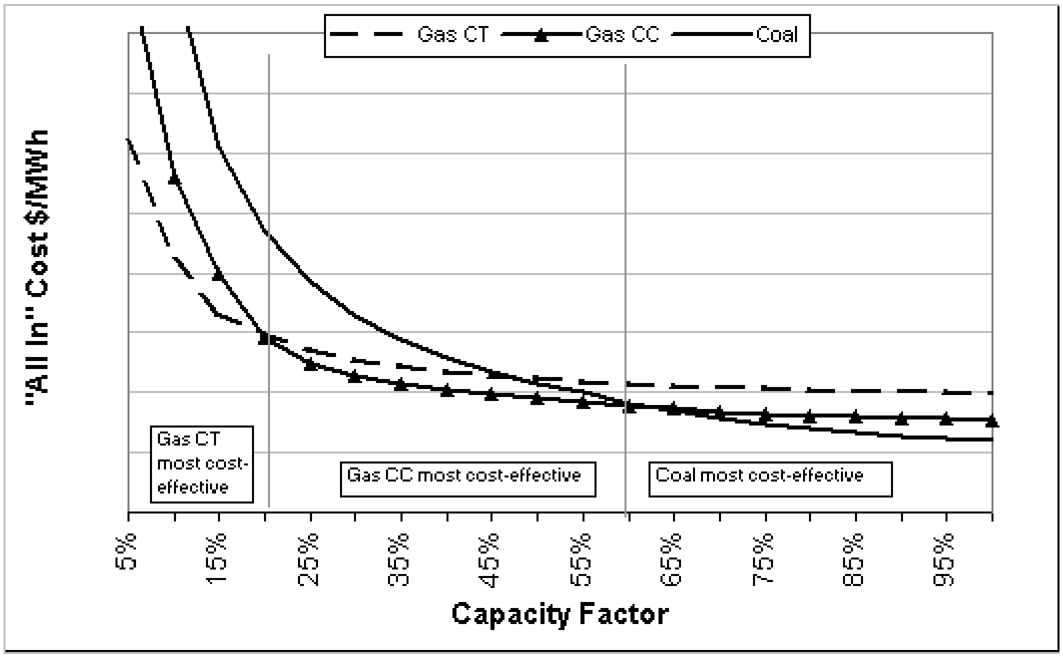
Different thermal generation technologies (peaking, intermediate, baseload) have distinctly different capital and operating cost characteristics. These characteristics dictate how various technologies are dispatched or used to serve load requirements of the system. The basic cost characteristics of thermal generation resource technologies are illustrated in the following table.

Table 2.1-1 General Cost Structure of Thermal Resources

Costs	Gas CT	Gas CC	Nuclear
Capital Costs	Low	Mid	High
Operating Costs	High	Mid	Low
Intended Use	Peaking	Intermediate	Baseload
Hours of Use	Low	Medium	High
$C0_2$ per MWh	Medium	Low	Zero

Figure 2.1-1 provides an illustration of how the general cost characteristics of gas CT, gas CCs, and nuclear generators might compare with one another based on how they are utilized (i.e., peaking, intermediate, or baseload) on the system. The figure shows that the overall cost (a.k.a., “all-in” cost) of electric energy per MWh depends highly on the number of hours a unit is operated, i.e., the unit’s capacity factor. The “all-in” cost curves decline as the fixed costs (capital and operations and maintenance costs) are distributed over more hours of operation.

Figure 2.1-1 General Cost by Resource Type and Capacity Factor



As seen in Figure 2.1-1, a gas CT unit is most cost-effective when utilized in a peaking role (less than 20% capacity factor in this illustration), with gas CCs and coal being most cost-effective in intermediate and baseload roles respectively.

Examples of Renewable Supply-Side Resources

1. Wind - These are typically large, three bladed turbines mounted atop high towers over 200 feet tall. Wind farms can consist of a single turbine or multiple turbines with aggregated capacities up to hundreds of MWs. Because the wind is what drives the turbines, the generation from a wind turbine is considered intermittent and can be difficult to predict. Consequently, the electric generation capacity that is attributed to wind turbines is less than the full design output rating. Wind generation units in Colorado typically have an annual capacity factor in the 30-40 % range.
2. Solar – Solar generation resources convert the Sun's energy into electricity. Solar generation can take several forms, such as photovoltaic ("PV"), concentrating PV, or concentrating solar thermal ("CSP"). Like the wind, solar generation is time and condition dependent. Solar generation is only available during the daytime and its output is coincident with the time of the day (i.e., as the sun rises and falls, so does the solar generation output). Maximum solar output (without storage) occurs prior to the time when electric demand reaches it highest level. Therefore, something less than the full nameplate generating capability of solar generation is counted toward meeting the electric system's peak demands.

3. Biomass – Biomass energy is derived from diverse energy sources such as wood and other organic matter, animal wastes, human refuse, and alcohol derived fuels. Landfill gas is a type of biomass generation using the methane gas produced by a solid waste landfill for combustion and power production. Biomass facilities are often base loaded energy sources with capacity factors of 80% or better.
4. Geothermal - Geothermal resources convert thermal energy stored in the Earth into electricity and are generally run as baseload facilities.
5. Hydroelectric – Flowing water is used in hydro plants where, generally, the flowing water's kinetic energy is used to rotate a turbine and generate electric power. Run-of-river units offer continuous energy contributions as long as water is flowing, while dammed or pumped storage units offer the ability to use the facility as a peaking unit thereby providing additional value to the resource.

Demand-side management ("DSM") resources act to reduce the demand for electric power and include a variety of measures such as energy efficiency, energy conservation, load management, and demand response. There are two basic types of demand side resources: peak shaving and energy reduction. Peak shaving DSM options are used to reduce a customer's demand and energy requirements during periods of high demand. An example of a peak shaving DSM option is a Public Service customer option called "Saver's Switch". Saver's Switch is a remote communication device that cycles residential air conditioning units' compressors on and off when load conditions on the electric system are significantly high. Energy reduction DSM options are used to reduce energy over all periods of the year. An example of an energy reduction option would be replacement of incandescent light bulbs with more energy efficient compact fluorescent bulbs to reduce energy consumption throughout the year. Energy Efficiency/Conservation saves demand at peak and some load Management/Demand Response save energy. But the primary objective of the energy reduction measures is to produce energy reduction and the primary objective of the peak shaving measures is to reduce peak demand.

Investments in transmission can be used as substitutes for investments in new generating facilities or demand-side resources, where transmission upgrades are used to access generation of other utility systems.

Planning Tools

Resource planners use a range of approaches to help identify the amounts, timing, and types of generation resources that should be added to meet increasing customer demand for electric power. One basic and straightforward tool is a load and resource balance or table ("L&R"). The function of an L&R table is to provide a comparison between the amount of electric generating Capacity and the peak load (or Demand) of a system plus planning reserves. In years when load (plus some added margin[1]) exceeds generation supply, additional generation capacity is needed. Table 2.1-2 provides a simple L&R table for a hypothetical electric system.

Table 2.1-2 Simple Load & Resources Table

		2011	2012	2013
(a)	**Owned Generation Capacity (MW)**	900	900	900
(b)	**Purchased Generation Capacity (MW)**	200	200	0
(c)	**Total Generation Capacity (MW)**	1,100	1,100	900
(d)	**Load Requirements**	700	800	900
(e)	**Reserve Margin (16%)**	112	128	144
(f)	**Total Load + Reserves (MW)**	812	928	1,044
(g)	**Resource Need (Excess/ Deficient)**	288	172	-144

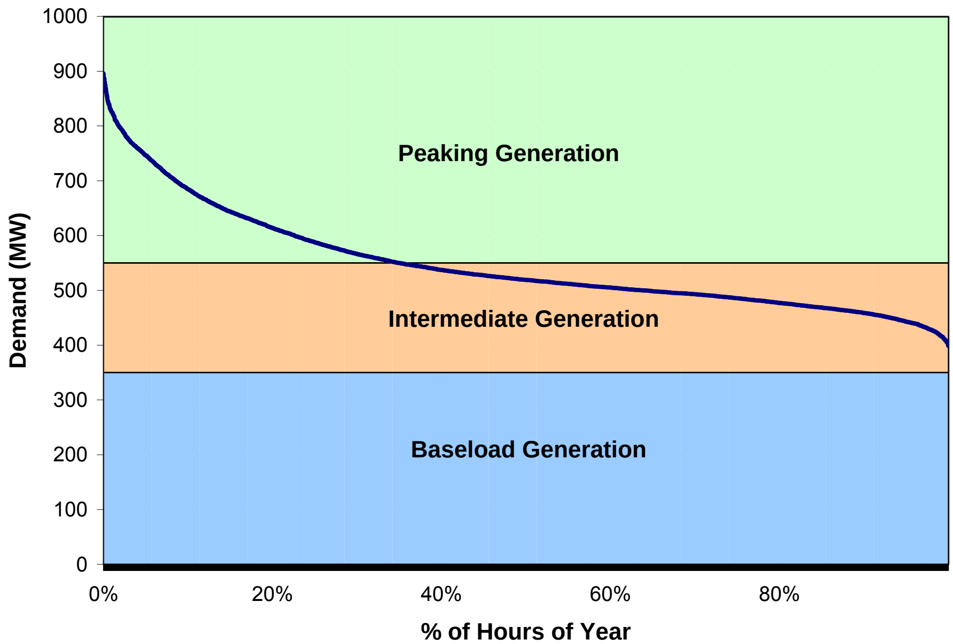
This L&R example provides insight into the amount and timing of future generation resource needs. First, note the reduction of purchased capacity expiring in 2013. By adding this reduction in capacity to the load growth of 100 MW per year, this fictitious electric system quickly loses its excess capacity by 2013.

Another useful tool for evaluating the needs of electric systems is the load duration curve. Load duration curves provide a graphic representation of how electric supply resources would operate to serve both the demand and energy requirements of the system. A load duration curve contains the total energy requirements of the system (typically over an entire year), sorted from the highest use hours to the lowest use hours. The highest number on the left hand side of the curve represents a peak energy usage during the highest energy day. The numbers on the right hand side generally represent overnight hours during the spring or fall when energy demand is low (for a summer peaking system). By overlaying the generation stack on top of the load duration curve, one gets a general idea of how much electric power each resource type (i.e., peaking, intermediate, baseload) would be required to produce over the year.

Figure 2.1-2 illustrates an electric system that is arguably short of baseload resources. As a result, this system will operate some of its intermediate resources in a baseload fashion.

[1] Reserve margin is additional generation capacity that can be used during any contingency including: higher than expected energy demand, unplanned generation outages, and inoperable transmission infrastructure.

Figure 2.1-2 Baseload Deficient



In contrast, Figure 2.1-3 illustrates an electric system that is arguably long on baseload resources. This system will operate some of its baseload resources at capacity factors (represented by % of hours of year) less that 40%.

Figure 2.1-3 Baseload Excess

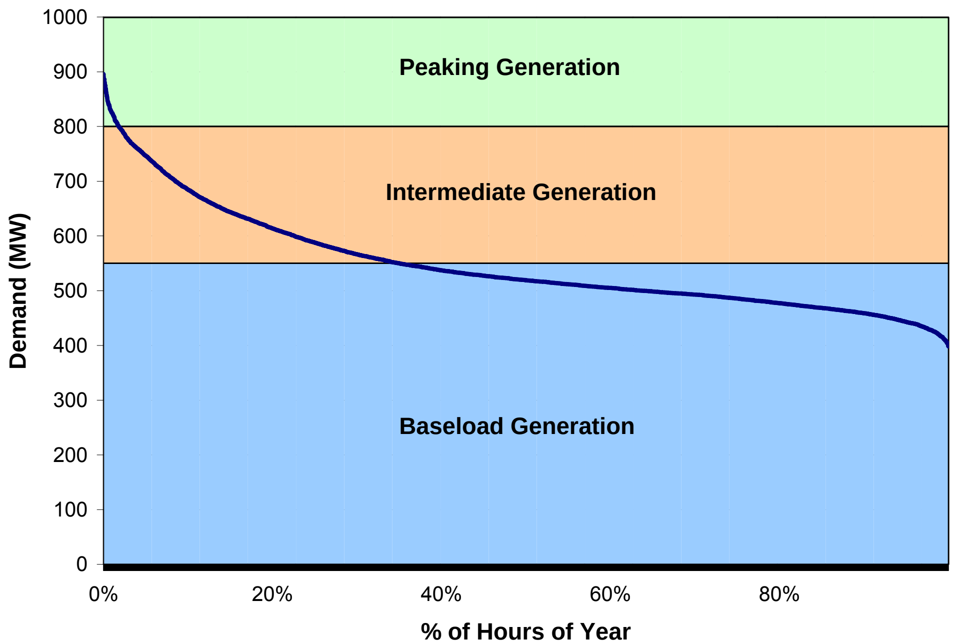
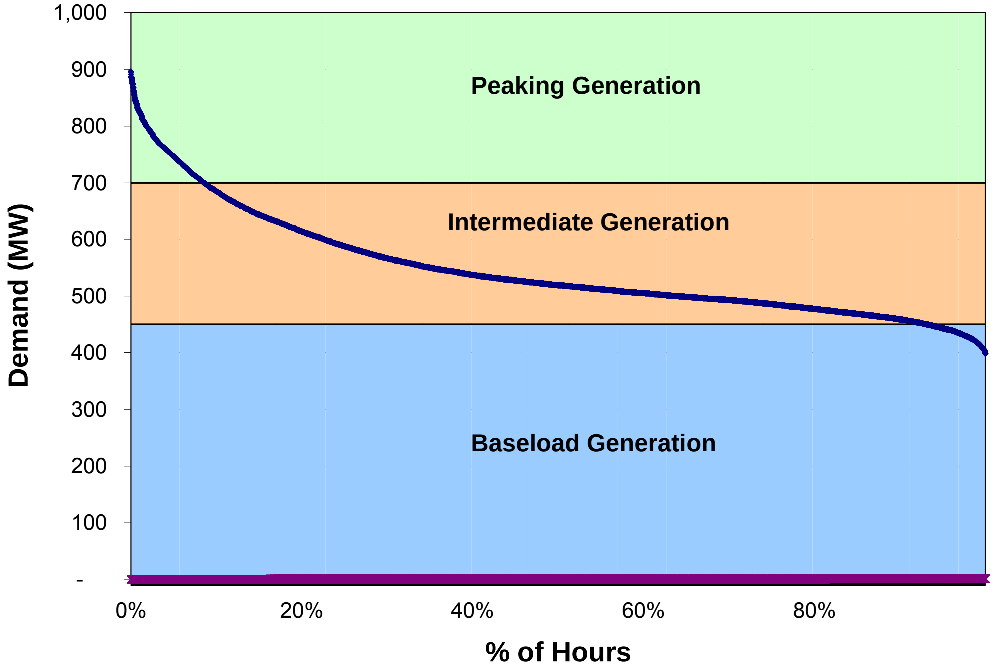


Figure 2.1-4 represents a system that is balanced and efficiently designed with the right quantities of generation resource types. Each resource has a specific role in meeting the overall system energy needs. Each type of resource provides the necessary levels of energy that result in the lowest system costs.

Figure 2.1-4 Balanced System



Computer Models

Having developed forecasts of customer demand, L&R tables and LDCs of the system, computer modeling of the electric system is often the next step in the planning process. Computer models allow the resource planner to examine how different resource technologies will integrate with the existing fleet to meet the system needs under a range of assumptions from key inputs such as fuel costs. A utility expansion planning model is specifically designed to construct combinations or portfolios of resources that would meet the capacity and energy needs of the system. The model simulates operation of each of these combinations of resources together with existing generation resources, while keeping track of all associated fixed and variable costs of the entire system.

The computer is needed because it can calculate costs, emissions, operational data, and various other metrics for each of the possible resource portfolios. Models typically have the capability to rank the various portfolios according to user-established objective functions, (e.g., minimization of average rates to customers, or minimization of net present valued of revenue requirements).

While this model is a powerful tool that can be used to generate and evaluate thousands of possible resource portfolios, the sheer complexity of resource evaluations of this magnitude would quickly overwhelm the model's data storage and computational capabilities unless steps are taken to limit the size of the optimization problem presented to the model at any one time. The number of resource combinations that can be generated each year grows exponentially depending on the number of resources made available to the model.

2.2 INDUSTRY OVERVIEW

Environmental Regulatory Challenges

Electric utilities must comply with an array of federal environmental regulations that govern the construction of new generating plants and the operation of existing facilities. In addition, the State of Colorado enacted the Clean Air-Clean Jobs Act. The following summarizes the major environmental regulatory programs that currently affect or have the potential to affect Public Service.

Regional Haze

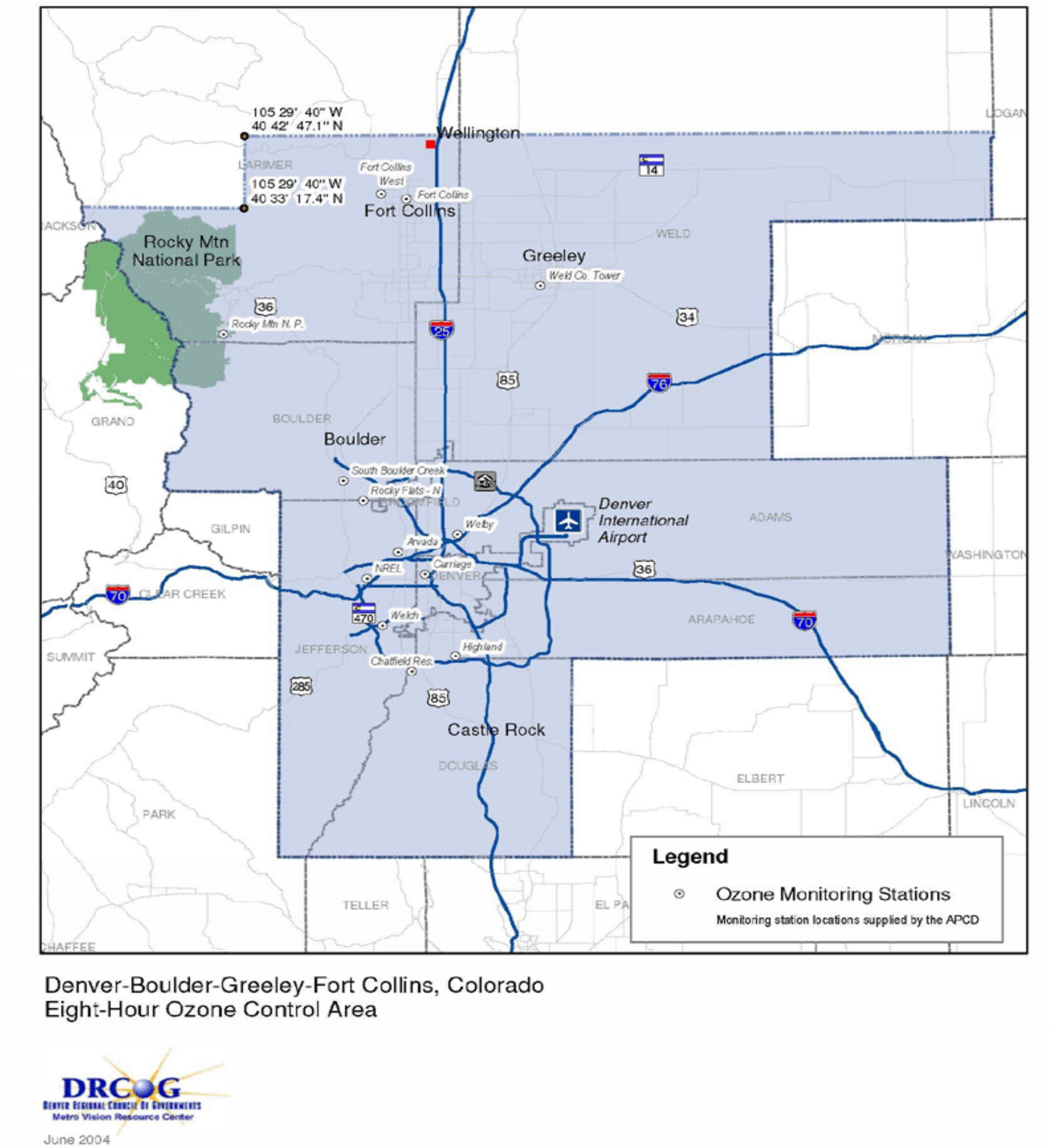
In 2010, the Colorado Air Quality Control Commission ("AQCC") completed a rulemaking process to meet the requirements of the Federal Regional Haze Rule to improve the visibility in Class I areas, such as National Parks and Wilderness Areas, across the country. The Regional Haze Rule includes Best Available Retrofit Technology ("BART") requirements for units built between 1962 and 1977. The Public Service units subject to BART include Hayden 1 and 2, Comanche 1 and 2, Cherokee 4, Valmont 5, Pawnee 1, and the Public Service portion of Craig Units 1 and 2. The Colorado Air Pollution Control Division developed a State Implementation Plan ("SIP") for the 12 regulated Class I areas in the state that identify the sources contributing to visibility impairment and establish control measures to improve visibility. This SIP required emission reductions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") for all BART units along with other non-BART electric generating units and non-utility sources such as cement kilns and industrial boilers. The Regional Haze SIP was approved by the AQCC in January 2011, passed by the State Legislature in May 2011, and submitted to the Environmental Protection Agency ("EPA") Region 8 for their review and approval. The Regional Haze SIP is expected to be finalized by the fall of 2012 with required emission controls for SO_2 and NO_x to be installed between 2014 and 2018.

Ozone

The Denver Metropolitan Area is currently designated as attainment for all Clean Air Act ("CAA") criteria air pollutants such as particulate matter less than 10 microns ("PM-10"), carbon monoxide ("CO"), SO_2, and NO_x. Since July 2007, however, the Denver area has not met the ambient air quality standard for ozone of 80 ppb and has therefore been designated as an ozone non-attainment area by EPA. Emissions of NO_x and volatile organic compounds ("VOC"s) react in the presence of sunlight to form ozone. This non-attainment area includes the entire Denver Metro area and parts or all of surrounding counties (Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson counties as well as parts of Larimer and Weld counties). Figure 2.2-1 shows the boundaries of the current Denver Metro ozone non-attainment area. This designation has a significant impact on the permitting of new generation resources in and around Denver. While the area is designated non-attainment, any new major sources or major modifications to existing sources will have to be permitted under the non-attainment area

New Source Review ("NSR") requirements. Thus, emission offsets for NO_x and VOC will be required along with the requirement to install emission controls that meet Lowest Available Emission Rate ("LAER"). LAER-based controls are very stringent and add significant expense and operating challenges to facilities. In March 2008 the EPA promulgated a new, more stringent ozone standard of 75 ppb over an 8-hour period. In addition, EPA is also in the process of evaluating whether the 8-hour ozone standard should be lowered to between 60 and 70 ppb to protect public health and the environment. This more stringent ozone standard will not only expand the boundaries of the current non-attainment area but will also require additional NO_x and VOC emission reductions from stationary sources to meet the lower standard. As a result, permitting of new electric generating stations, both Company-owned and Independent Power Producer resources, will be more difficult in and around the Denver Metro area.

Figure 2.2-1 Denver Ozone Non-Attainment Area



Hazardous Air Pollutants

In May 2011, EPA proposed new rules for the control of hazardous air pollutants ("HAP"s) from coal-fired electric generating units. These rules will require the installation of Maximum Achievable Control Technology ("MACT") to control acid gases such as hydrogen chloride, mercury and non-mercury metal HAPs such as arsenic, cadmium and lead. Emission controls such as scrubbers to control acid gases, baghouses for non-mercury metal HAPs and sorbent injection to control mercury will be required to meet these new standards. Final promulgation of these emission standards for hazardous air pollutants is expected by the fall of 2011. The proposed compliance schedule is 3 years after final promulgation with an option for a one year extension if the source needs to install a scrubber to meet the acid gas limits.

Clean Air-Clean Jobs Act

In April 2010, HB10-1365 – The Clean Air-Clean Jobs Act ("CACJA") was signed into law. This legislation created a framework to enable Colorado utilities to respond to the wave of CAA and other environmental regulatory challenges facing coal-fired generating resources over the next decade. The CACJA required Public Service to file an emissions reduction plan to achieve at least 70% to 80% reduction in annual emissions of NO_x, as measured from 2008 levels, on a minimum of 900 MWs of existing coal-fired generation in Colorado. The plan was required to consider both current and reasonably foreseeable CAA requirements and allowed the Company to propose emission controls, plant refueling, or plant retirements to meet the NOx reduction requirements of the legislation. Public Service submitted a plan to the Commission on August 13, 2010.

The Commission approved the following emission reduction plan that was in turn incorporated into the Regional Haze SIP by the AQCC in January 2012:

- Shutdown of Cherokee 1 (2012), Cherokee 2 (2011), and Cherokee 3 (2016)
- Fuel switch Cherokee 4 to natural gas by the end of 2017
- Construct a new 2x1 natural gas combined cycle plant at Cherokee Station
- Shutdown Arapahoe 3 and fuel switch Arapahoe 4 to natural gas by the end of 2013
- Shutdown Valmont Unit 5 by the end of 2017
- Install selective catalytic reduction ("SCR") for controlling NO_x, a scrubber to control SO_2 and sorbent injection for mercury control on Pawnee Unit 1 by the end of 2014
- Install SCRs for controlling NO_x on Hayden Units 1 and 2 in 2015 and 2016, respectively

Through this integrated plan of scheduled retirements, fuel switching and installation of emission controls, Public Service will be able to meet the requirements of Regional Haze, ozone non-attainment, and utility boiler hazardous air pollutant requirements without the addition of controls beyond those noted in the CACJA plan above.

Greenhouse Gases

As of January 2, 2011, the EPA has been regulating the greenhouse gas ("GHG") emissions from stationary sources through the New Source

Review/Prevention of Significant Deterioration program. GHG's are a single regulated air pollutant defined as the aggregate group of the following six gases:

- Carbon dioxide
- Nitrous oxide
- Methane
- Hydrofluorocarbons
- Perfluorocarbons
- Sulfur hexafluoride

Each of these gases has a specific global warming potential, as compared to carbon dioxide, that is used when calculating the total GHG emissions from a source. New sources with GHG emissions above 100,000 tons/yr and modified sources with GHG emissions above 75,000 tons/yr must go through a technology-based, source by source review process to demonstrate that they will use the Best Available Control Technology ("BACT") to control GHG emissions. Both new and modified sources must complete this GHG BACT process to receive a new air emission construction permit. At this time, GHG BACT for sources like combustion turbines and boilers is focused on improving efficiency by generating more electricity with less fuel usage or heat input. BACT for GHGs will likely become more stringent over time as actual emission control technologies like carbon capture and sequestration become commercially available or power plant technologies become more efficient.

EPA has stated its intention to propose GHG New Source Performance Standards for new and existing power plants. The proposal has been delayed, but EPA currently intends to release a final rule in 2012. New gas-fired generation will meet the EPA BACT standards for GHG.

Regulation of Coal Ash

Public Service's power plant operations generate hazardous waste that are subject to the Federal Resource Recovery and Conservation Act and comparable Colorado laws that impose detailed requirements for the handling, storage, treatment and disposal of hazardous waste. In June 2010 EPA proposed a rule seeking comment on whether to regulate coal combustion byproducts (often referred to as coal ash) as hazardous or non-hazardous waste. Coal ash is currently exempt from hazardous waste regulation. If EPA ultimately issues a final rule under which coal ash is regulated as hazardous waste, Public Service's costs associated with the management and disposal of coal ash would likely increase and the beneficial reuse of coal ash would be impacted. The final rule from EPA on possible changes to coal ash regulation is expected in 2012.

Electricity Consumption and CO_2 Emissions

In its Decision No. C08-0929, Phase 1 decision in 2007 ERP, the Commission ordered Public Service to address, through its testimony filed with its next ERP, a strategy for improving public knowledge concerning the relationship between electricity consumption and CO_2 emissions, including key messages and channels. Public Service was ordered to include the partners it had identified and contacted to serve as partners in the education strategy.

In October 2011, Public Service met with representatives of the Governor's Energy Office, the Colorado Department of Public Health and Environment, the Office of Consumer Counsel ("OCC") and Commission Staff to discuss the actions the Company has already taken to educate customers about carbon dioxide emissions and its relationship with electricity consumption. The Company also discussed future plans. The group was supportive of the Company's strategy and made suggestions to enhance customer education. All parties felt the Company could provide more information about historical emissions (such as SOx, NOx and CO_2) to illustrate the trend in emission reductions. The parties felt it was important to report this information in one place, such as the corporate website. The group suggested that the Company could supply additional information about costs and impacts of different fuel sources.

The OCC recommended that customers should understand the difference between watts and lumens. The group had recommendations about the Company's recent O-Power pilot, which provides benchmarking information by comparing customer usage against neighborhood peers. Specifically, they wanted to learn about customer feedback and future plans. They suggested we include more energy efficiency tips and carbon emissions in the customer benchmarking report. They suggested additional ideas in how we could educate customers through the on-line bill format.

Public Service feels like this was a successful meeting and will prioritize these ideas based on ease of implementation and cost effectiveness. Public Service plans to update the stakeholder group in 2012.

Fuel Adequacy – Natural Gas

Introduction

While the 2011 ERP's alternative plans all increase the Company's natural gas consumption or "burn," Public Service is reasonably assured that adequate natural gas resources will be available to Public Service. The consensus view produced by the resource assessments is that many decades, 60 to 70 years, of potential gas supply remains. A short review of four such assessments follows below.

Gas Resource Assessments

As a generator and local distribution company with no involvement in the upstream natural gas exploration and production industry, Public Service relies on industry participants and experts for expertise relating to large scope natural gas resource assessments. However, a sizeable number of studies are available. Numerous enterprises, organizations and government agencies develop gas resource estimates periodically. A short list includes evaluations by the Energy Information Administration ("EIA") and Department of Energy ("DOE"), the Potential Gas Committee ("PGC"), the Massachusetts Institute of Technology ("MIT"), the National Petroleum Council ("NPC"). A summary of these four estimates is shown in Table 2.2-1. "Tcf' denotes a trillion cubic feet of natural gas.

Table 2.2-1 Gas Resource Review Summary

Study	Study Element	Proven Reserves Assumption (Tcf)	Study Mid-Point (Tcf)	Total Remaining Resource (Tcf)
EIA	Proven Dry Gas Reserves on 12/31/09	273	NA	NA
EIA	Total Unproved Resources (12/31/08 EIA Reserve Estimate)	245	2,298	2,543
PGC	Potential Resource (12/31/09 EIA Reserve Estimate)	273	1,897	2,170
MIT	Total U.S. Gas Resource Estimate (ICF) (12/31/08 EIA Reserve Estimate)	245	1,857	2,102
NPC	Total Remaining Gas Resource Base	NA	2,300	2,300

Sources: EIA: Annual Energy Outlook; PGC: Potential Supply of Natural Gas in the United States; MIT: The Future of Natural Gas; NPC: Prudent Development– Realizing the Potential of North America's Abundant Natural Gas and Oil Resources.

Proven Reserves

Regarding proven reserves, EIA/DOE issues an annual estimate called *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, which is widely accepted as a measure of gas reserves that geologic and engineering data indicate may be recovered in future years under existing economic conditions with known technology. EIA's proven reserve estimate contains the same reserve figures reported to the Security and Exchange Commission and the reserve figures reported by private operators large enough to be required to file a Form EIA-23. The quantities held by smaller operators, about 5% of total reserves, are estimated by EIA/DOE.[2]

It should be noted that over the past 10 years, companies reporting on Form EIA-23 have increased their combined proven reserved estimates 54% from 177 Tcf in the 2000 report to 273 Tcf for the year ending December 31, 2009. Much of the increase in proven reserves is due to the advent of gas-shale reservoir development. Beginning in the mid-2000s, the natural gas exploration and production industry began a rapid shift to the combined application of horizontal drilling and well-bore fracturing techniques in tight sand and shale reservoirs. These deposits may once have been identified as source rock for adjacent sandstone-type reservoirs, but considering the conventional drilling and completion techniques in use before 2005, were considered too dense for economic production themselves. The popular press has reported this activity, and each assessment in Public Service's research noted the dramatic movement toward shale gas development.

In addition to compiling reserve estimate history, EIA/DOE also projects future proven reserves. In their *Annual Energy Outlook ("AEO") 2011,* proven reserves are expected to increase to 314 Tcf by the year 2035.[3]

Undiscovered / Unproven Resources

Beyond proven reserves, consumer and producers are both concerned with additional potential gas resources, quantities that are not currently leased or owned, or may not yet be discovered. Several researchers have adopted the convention of identifying the total remaining natural gas resource, including proven reserves. In the assumptions document for the AEO, EIA also presents their natural gas resource-base assumption of 2,543 Tcf, based on assessments by the U.S. Geological Survey ("USGS") and the Bureau of Ocean Energy Management, supplemented with additional non-conventional natural gas resources outside the USGS scope.[4] Their AEO 2011 edition used year-ending 2008 proven reserves.

The PGC is an independent, non-profit organization composed of volunteer geologists, geophysicists, and petroleum engineers that has published a biennial National Resource Assessment of the natural gas resource base

[2] Summary: U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Proved Reserves 2009, November, 2010. U.S. Energy Information Administration, U.S. Department of Energy Washington, DC 20585. Report Number: DOE/EIA-0383(2011), April 2011. http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf accessed September 22, 2011

[3] Annual Energy Outlook with Projections to 2035, July 2011. U.S. Energy Information Administration, U.S. Department of Energy Washington, DC 20585. Report Number: DOE/EIA-0383(2011), April 2011. http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf accessed September 22, 2011

[4] Assumptions to the Annual Energy Outlook, U.S. Energy Information Administration, U.S. Department of Energy Washington, DC 20585. Report Number: DOE/EIA-0554(2011), July 2011. http://www.eia.gov/forecasts/aeo/assumptions/ accessed September 22, 2011

since 1964. Their 2011 report, *Potential Supply of Natural Gas in the United States*, published in abstract pending the official fall 2011 release, estimates a total potential natural gas resource of 1,898 Tcf including coal-bed methane deposits, a 4 percent increase over their previous estimate.[5] This figure does not include 273 Tcf of proven dry-gas reserves reported by EIA/DOE for year-ending 2009, resulting in a total future supply of 2,170 Tcf.

MIT's Energy Initiative recently sponsored the publication of *The Future of Natural Gas*, which included a survey of existing studies, including the EIA AEO 2011 and the 2008 edition of PGC's biannual report, and contracted an independent consultant, ICF International, to run ICF's hydrocarbon model with MIT-specified inputs. Their estimated resource base (using the 2008 EIA proven reserves value) was 2,102 Tcf.[6] MIT's study also develops a North American supply cost curve that showed up to 1,000 Tcf could be produced at a price of $5.00 per Dth (using 2007 dollars).

In September 2011, The National Petroleum Council ("NPC") addressed the entire petroleum and natural gas supply chain for the Secretary of Energy in *Prudent Development–Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*. As part of the study to evaluate the entire North American resource base, the NPC surveyed 14 separate North American natural gas resource assessments, including 8 assessments of the 48 lower U.S states (including the three previously discussed) and compiled a range of resource base estimates, from a Low Scenario of 1,500 Tcf to a High Scenario of 4,000 Tcf, using 2,300 Tcf as the Mid Scenario.[7] The NPC also estimated a Canadian Mid Scenario of 900 Tcf.

<u>Consumption and Expected Resource Life</u>

An idea of how long these reserves might last may be inferred by understanding natural gas consumption trends. Since 2000, gas consumption has been between 22 and 24 Tcf annually, varying in response to weather and economic conditions. 24 Tcf of gas was consumed by all end-users in the United States, as reported by the Energy Information Administration of the Department of Energy ("EIA/DOE") in *Natural Gas Monthly.*[8] However, future consumption is expected to grow not only with population growth, but also as more gas-fired generation is installed. In EIA's

[5] Potential Supply of Natural Gas in the United States (December 31, 2010), Potential Gas Agency, Colorado School of Mines, Golden, CO 80401-1887. http://www.potentialgas.org/

[6] Massachusetts Institute of Technology, The Future of Natural Gas an Interdisciplinary MIT Study. Obtained: 9/23/11 at http://web.mit.edu/mitei/research/studies/naturalgas.html accessed September 22, 2011

[7] http://www.npc.org/Prudent_Development.html accessed September 22, 2011

[8] Natural Gas Monthly August 30, 2011U.S. Energy Information Administration, U.S. Department of Energy Washington, DC 20585. Report Number: DOE/EIA□0130(2011/08). http://www.eia.gov/oil_gas/natural_gas/data_publications/natural_gas_monthly/ngm.html accessed September 22, 2011

AEO reference case, gas consumption grows 0.9% per year from 23 Tcf in 2009 to over 27 Tcf in 2035, consuming a total of 650 Tcf between 2011 and 2035.[9]

At rates of gas consumption recorded in 2010 (about 24 Tcf), the lowest resource estimate in Table 2.2-1 (the 2,102 figure from the MIT study) would be exhausted in 87 years. And if gas consumption growth were to continue at the 0.9% per year forecasted by the EIA in AEO 2011, the MIT resource base would be last 64 years. However over-simplified this type of evaluation may be, it does provide a sense of scale and perspective of natural gas' future role in the economy in relation to the enormous size of potential supplies.

In view of the magnitude of recent gas resource estimates, Public Service and the 2011 ERP stakeholders can be reasonably assured that gas supplies will be available throughout the RAP and the Planning Period.

Fuel Adequacy - Coal

Public Service currently has three coal-fired generating facilities that burn Powder River Basin coal. They are Arapahoe Station in Denver, Pawnee Station in Brush and Comanche Station in Pueblo. Public Service will retire Arapahoe Station from coal-fired operations in 2013. The remaining facilities burn a combined estimated 7.5M tons of Powder River Basin ("PRB") coal annually. Based on information from the USGS, EIA, mining consulting companies, and actual vendor information, Public Service believes the coal resource in the PRB to be of sufficient size, based on current production levels and production costs, to be able to provide cost-effective coal to Public Service facilities for at least 30 years. The basis for this determination is widely accepted and available information that is used to determine resources, production costs, mining impediments, and future cost effectiveness of coal supplied from the Powder River Basin of Wyoming and Montana.

Coal Resources

The Powder River Basin of Wyoming and Montana is the largest coal producing region in the world, supplying over 40% of the coal consumed for power generation in the United States. Information from EIA and the USGS indicated that demand over the next 30 years would be approximately 17 billion tons while the coal resource in the PRB exceeded 140 billion tons. More specifically the area that supplies coal to Pawnee and Comanche is estimated by the USGS to contain 24 to 34 billion tons of economically recoverable coal during the next 30 years. Thus, in the Gillette coal field area alone, there are sufficient resources to supply coal to both Pawnee and Comanche.

[9] Annual Energy Outlook with Projections to 2035, July 2011. U.S. Energy Information Administration, U.S. Department of Energy Washington, DC 20585. Report Number: DOE/EIA-0383(2011), April 2011. http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf accessed September 22, 2011

To further assess resource availability, a review of the coal accessible to the operating mines and selection of development projects in the PRB as of year-end 2010 was conducted by mining consultant John T. Boyd Company. Each mine or project was evaluated independently, with production requirements estimated, and available coal resources assessed in specific tracts logically mineable by the operation. The results of this mine-by-mine evaluation indicated that 20.5 billion tons of the 34 billion tons of economically viable resources are mineable from existing or planned operations. See Table 2.2-2.

Table 2.2-2 Evaluation of PRB Coal Resource

	Tons (Millions)
Resources Within Mine Permit Areas	5,773
Resources Recently Leased or Identified for Leasing	4,680
Resources Logically Mineable Within a Mine's Area of Interest	10,113
Total	20,566

This site specific analysis further demonstrates that sufficient resources are available to support planned mining over the 30 year period. Moreover, as indicated by the USGS study, extensive additional resources are available beyond the areas identified.

<u>Cost Trends for PRB coal</u>
Typically as a coal basin matures, mining proceeds from the most favorable to less favorable resources, a trend which puts upward pressure on costs. Generally speaking, this is the case in the PRB, particularly in the Gillette area where the mines are progressing from shallower, less expensive resources on the eastern edge of the basin to more deeply-buried and thus more costly resources to the west. In addition, physical factors such as road relocations and coal haul distances will tend to increase costs. This increase, however, will occur very slowly due to the nature of the deposit and scale of operations. Industry forecasts of average mining costs indicate a modest increase of ±1% per year in real terms from about $10/ ton (constant 2011 dollars) to about $15/ton in 2040. The mine production costs and eventually the price of coal for Public Service would indicate that the fuel would remain reasonably priced over the next 30 years.

<u>Summary</u>
In summary there is sufficient coal available for both Pawnee and Comanche in the near and long term and it will remain reasonably priced during the 30 year horizon.

<u>Storage Resources</u>
Xcel Energy Inc. ("Xcel Energy") has demonstrated a commitment to diversifying its generation portfolio and to implementing a strategic vision of a clean energy future.

However, as more intermittent resources are added to the generation portfolio and as these resources meet a greater amount of customers' firm obligation load, system operational challenges, such as balancing load and generation, will become more complex and will require new solutions. Thus, Xcel Energy is exploring innovative ways to integrate intermittent resources. Energy storage technologies are viewed as strategic to Xcel Energy because of the increasing wind and solar PV penetrations on all of its operating systems.

Specifically, Xcel Energy is investigating energy storage technologies to mitigate the system impacts from large penetrations of intermittent resources. Energy storage provides more system control and balance, supporting:

- Generation – "Time Shifting" wind output to minimize the impact of the intermittency and variability of intermittent resources and to reduce the wear and tear on thermal resources;
- Transmission – Providing ancillary services
- Distribution – Regulating voltage, improving the match between the solar PV generation peak and the distribution system load peak, and reducing demand during peak periods (peak shaving)
- Individual customers – Providing power quality, peak shaving, and back up power.

<u>Energy Storage Technologies</u>

A number of utility-scale energy storage technologies are available today, including:

- Pumped-hydro (the largest contributor on a world-wide basis);
- Compressed air energy storage ("CAES");
- Batteries, e.g., lithium ion, sodium sulfur, lead-acid;
- Flywheels;
- Capacitors;
- Thermal, e.g., solar thermal molten salt, ice.

The choice of which technology to use for a given application depends upon the amount of sustainable peak power output required for charging/discharging and required duration discharge at maximum discharge rate, i.e., total kWh, MWh stored. Figure 2.2-2 below shows the utility applications for energy storage with various combinations of power and energy, and Figure 2.2-3 shows the effective ranges of several electric storage technologies corresponding to those applications. Thermal storage technologies generally vary in peak power output up to tens of MW and usually store up to several hours of energy.

Figure 2.2-2 Utility Applications for Energy Storage

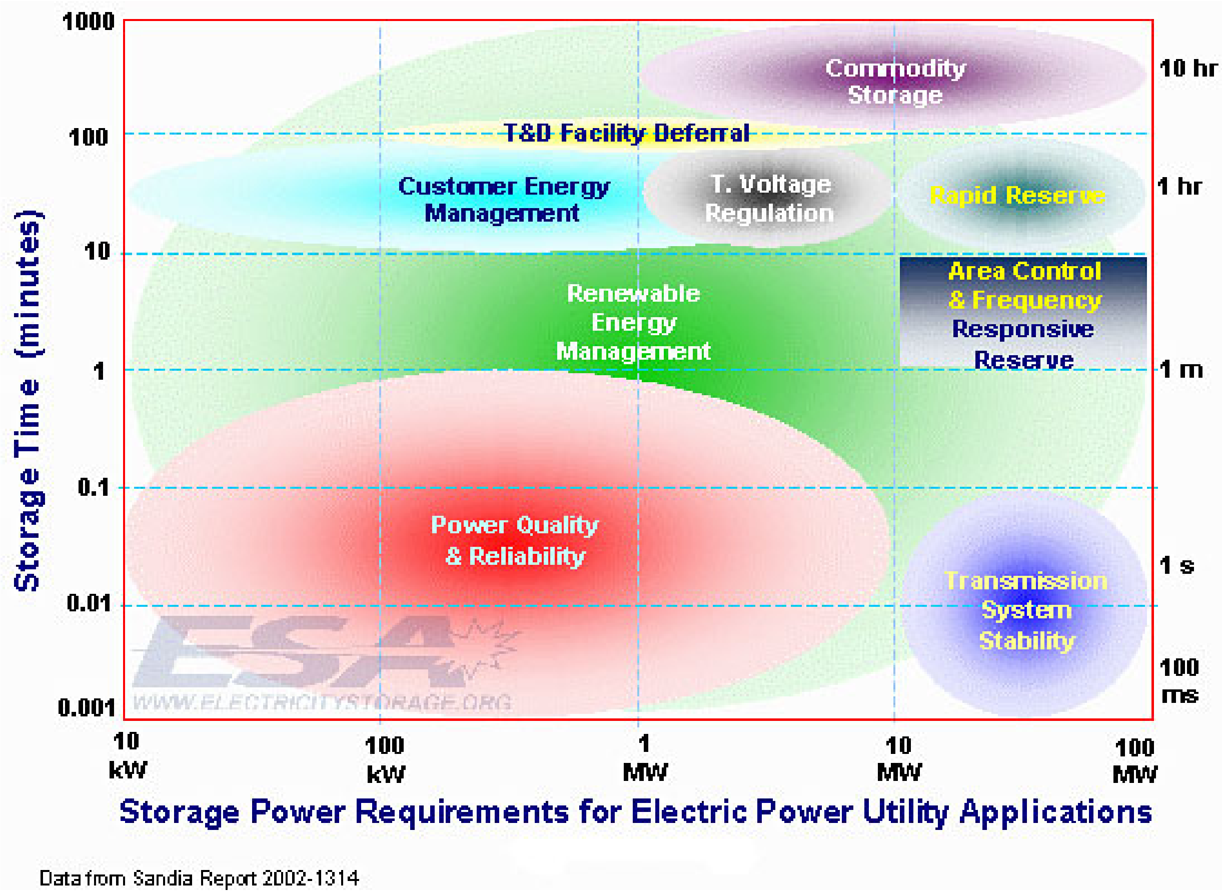
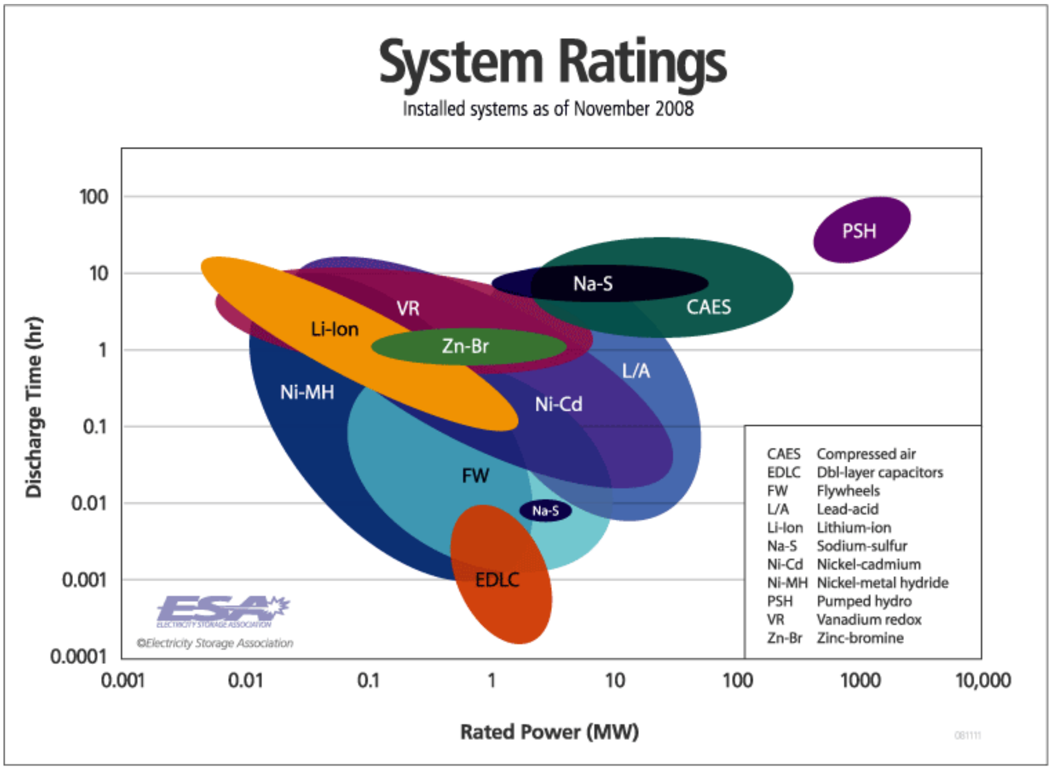
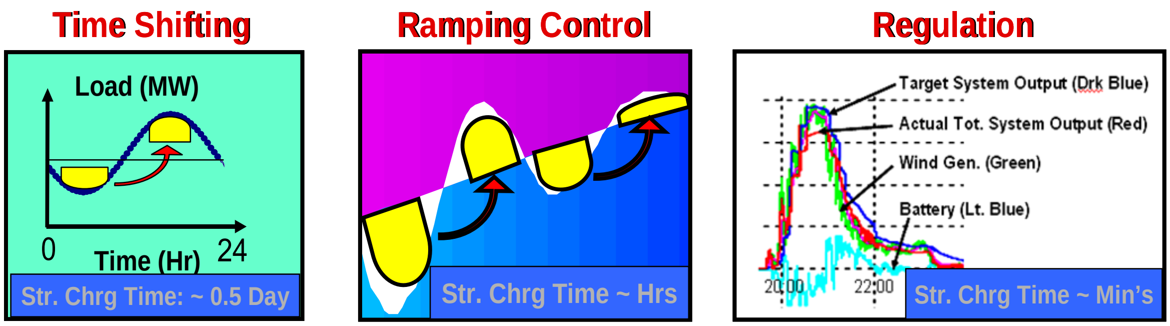


Figure 2.2-3 Electric Energy Storage Technologies – System Ratings



<u>Value Elements of Storage Used For Integrating Variable Renewables</u>
The key elements of value obtained from energy storage with respect to integrating intermittent resources are summarized in Figure 2.2-4.

Figure 2.2-4 Value Elements of Storage for Renewable Integration



- **Arbitrage**
- **Constraint Relief**
- **Curtailment Avoidance**
- **Load/DG Matching**
- **Peak Shaving**

- **Reduced generator cycling**
- **Reduced reserve requirements (gas & elect)**
- **Voltage stability (distribution)**

- **Frequency – "Reg Up/Reg Down"**
- **Voltage/VAR support**
- **Fast response to system perturbations**

Source: EPRI

While all of these elements provide value to a utility system, the key factors driving energy storage economics with respect to these elements are:

- The spread between cost of off-peak and on-peak energy which is most influenced by natural gas prices and assumed carbon dioxide emission prices;
- Storage costs (capital, O&M, charging energy, and efficiency loss);
- Penetration levels of the intermittent resources (affecting wind/solar integration costs, power plant cycling costs, curtailment frequency/duration and transmission and distribution system constraints), and;
- The penetration of storage itself which influences the marginal cost of energy when energy storage is prevalent.

Economic analyses of energy storage options and their cost/benefits in high penetration of intermittent resources scenarios must include a range of assumptions for all of these factors.

<u>Energy Storage Research and Demonstration Projects</u>

Xcel Energy monitors energy storage technology developments on an ongoing basis through its membership in the Electric Power Research Institute's ("EPRI") Energy Storage Program (and chairmanship of the program's advisory council), membership in the Energy Storage Association and involvement in energy storage conferences (both as participants and as expert panelists/speakers). Xcel Energy is also involved in ongoing efforts to model the value of energy storage on its operating systems, including large-scale batteries (greater than 50 MW), pumped hydro, and CAES systems.

In December of 2010, EPRI produced a document entitled, Electricity Energy Storage Technology Options - A White Paper Primer on Applications, Costs, and Benefits. The document is available to the public and can be downloaded at:

http://my.epri.com/portal/server.pt?Abstract_id=000000000001020676

This document provides, among other details, a listing of available electric energy storage technologies, along with their current costs, applications and advertised performance characteristics. While some of these technologies appear to have promise, many of the energy storage system cost, performance, and cycle-life data presented have yet to be validated by real-world field trials. The report cautions, "With some exceptions, very few of the systems discussed in this report have been fully tested and verified at the scale of the stated applications. Therefore, uncertainties in cost, performance, and cycle life as well as technology operational risk should be considered when planning for the use of these resources."

From the referenced EPRI document, it can be seen that energy storage technologies today are more expensive than conventional supply resources. Of the current bulk energy storage options (greater than 1 MW and greater than four to six hours of discharge), only the pumped hydro and CAES technologies have total life cycle costs that have the potential to compete with traditional resources in the relative near-term. Siting for both of those technologies is limited, however, since they require geologic features, e.g., large elevation changes, access to water, salt deposits of sufficient size and at appropriated depths (pressures) etc., not often found in locations ideally positioned to support the electric system from supply resource perspective.

Xcel Energy and Public Service continue to assess utility-scale energy storage potential. Xcel Energy has been active in demonstrating and learning from energy storage technology applied in real-world, utility applications, focused on the integration of variable renewables.

- Xcel Energy's first project, commissioned in 2006, is a hydrogen energy storage ("Wind2Hydrogen") demonstration at the National Renewable Energy Laboratory ("NREL") in Golden, which is still operational and being actively tested by NREL;
- The second project commissioned in 2009 is a 1 MW, 7 MWh sodium sulfur battery wind integration ("Wind2Battery") demonstration in Luverne, MN, in partnership with NREL and the University of Minnesota;
- The third project to be fully commissioned in 2011 is the 1.5 MW, 1 MWh Xtreme Power large, utility scale battery energy storage

system at the SolarTAC facility in Aurora, CO as part of a three-year test program with Xtreme Power to evaluate how energy storage can assist in operating a distribution system with high levels of solar production in comparison to the customer loads on the system.

- Xcel Energy also plans to participate in a proposed megawatt-scale CAES demonstration project with a leading oil & gas company in Texas.

Conclusions

The energy storage value proposition is evolving. Energy storage technologies today are expensive. Except in certain circumstances, broad deployment of energy storage solutions is not expected until costs come down appreciably. There are indications, however, that storage technology costs (for those other than pumped hydro and CAES, which are relatively mature and challenging to site) could come down significantly, to the point where they may effectively compete. Moreover, energy storage has the potential to provide additional, often difficult to value, services that traditional resources cannot provide such as the following:

- Storage serves both as a load and a generation source providing operational flexibility
- Distribution-sited energy storage, providing both voltage support & congestion relief during system peak hours, can also be aggregated to serve bulk storage functions, including wind energy time shift and wind energy curtailment avoidance, thus potentially mitigating significant impacts from both solar PV and wind variability with a common energy storage resource

Public Service's experience suggests that conventional supply resources, when coupled with limited wind curtailment, should continue to be adequate for mitigating the variability of wind and solar energy penetrations. Public Service's 2G/3G Wind Integration Cost Study (see Section 2.14) determined that additional storage resources provide some but limited potential for reducing wind integration costs. Public Service believes that the study results indicate that the level of storage resources on Public Service's system are reasonably adequate and that there is reduced value for arbitrage between off-peak and on-peak energy values.

Public Service continues to study the potential value opportunities for energy storage on its electric grid and to monitor developments in energy storage technologies and their costs so that, when appropriate to do so, customers will benefit from energy storage resource additions.

Federal PTC Extension

The Section 45 federal production tax credit ("PTC") for electricity produced from wind resources expires at the end of 2012. Legislation has been introduced in Congress to extend this credit, but neither the U.S. House of Representatives nor

U.S. Senate has voted on the measures. While there has historically been bipartisan support for this credit, Public Service is pessimistic about its continuation given budgetary pressures facing the federal government and expects prolonged debate on continuation of the credit at the current level.

Public Service will evaluate wind resources without the PTC for years after the scheduled expiration of the PTC in 2012 unless Congress acts to extend the PTC before the Phase 2 evaluation.

Accounting Considerations for PPAs

Certain accounting principles related to variable interest entities, leases and derivatives present financial challenges as they relate to purchases of energy and capacity by utilities through power purchase agreements (“PPAs”).

Variable Interest Entities

Effective Jan. 1, 2010, Xcel Energy adopted new guidance on the consolidation of variable interest entities contained in Accounting Standards Codification (“ASC”) 810 “Consolidation.” The guidance requires enterprises, such as Public Service, to consider the activities that most significantly impact an entity’s[10] financial performance, and the enterprise’s ability to direct those activities, when determining whether an entity is a Variable Interest Entity (“VIE”) and whether an enterprise is the VIE’s primary beneficiary. If it is determined that an enterprise is the primary beneficiary of the VIE, the standard requires that the VIE’s financial statements be consolidated into the financial statements of the enterprise.

Public Service is generally interested in avoiding the consolidation of independent power producing entity’s financial statements given the potentially negative effect that consolidation could have on Public Service’s financial metrics such as:

- Debt-to-Equity
- Interest Coverage
- Return on Assets
- Operating Margins
- Enterprise Value/EBITDA
- Timing of Recovery – Regulatory (difference between cash flow and return on assets)

Generally, an entity may be a variable interest entity if there are terms that require the power purchaser to absorb financial risks or to accept benefits that are not in proportion to their "interest" in the entity.

[10] The entity of concern in this discussion is an Independent Power Producer with a PPA with Public Service.

Broad focus on economic performance of the entity is required in the evaluation of whether an enterprise is an entity's primary beneficiary. The standard involves significant judgment and requires the variable interest holders to weigh their ability to direct the activities that most significantly impact the entity's financial performance against such powers of other variable interest holders. Furthermore, an enterprise may be considered the primary beneficiary of a VIE irrespective of an apparent lack of power to direct certain benefits and risks, if the ability to direct those benefits and risks are implicit in the PPA arrangement.

The primary beneficiary evaluation requires an assessment of what activities have the greatest impact on the entity's economic performance. That assessment may include a determination of which areas present the greatest risk of potential variability from expected performance or the greatest likelihood of variability. Further considerations may include an assessment of the term of the PPA in relation to the entity's economic life.

Typical areas impacting economic performance of a power plant may include:

- Investment risk
- Output price risk
- Commodity price risk (fuel, electricity)
- Residual value risk
- Operations and maintenance risk (including efficiency and technology risk)
- Environmental policy/regulatory risk
- Tax risk
- Credit risk
- Catastrophe risk
- Site/location/construction risks
- Transmission cost pass-through
- Financing
- Other
    - Curtailment
    - Production Tax Credits
    - Investment Tax Credits

<u>Leases</u>

Public Service is generally interested in avoiding capital leases due to the potentially negative effect that capitalization of lease assets and obligations on the Company's books in the manner that ASC 840 requires could have on items such as:

- Debt-to-Equity
- Interest Coverage
- Return on Assets
- Operating Margins

- Enterprise Value/EBITDA
- Timing of Recovery – Regulatory (difference between cash flow and return on assets)

ASC 840 "Leases" provides the primary accounting guidance in determining whether an arrangement, such as a PPA, contains a lease. Under ASC 840, a lease is evident when each of the following criteria is met:

1. Specific property, plant, or equipment ("PP&E") is identified;
2. The fulfillment of the arrangement is dependent on the use of the identified PP&E; and
3. The arrangement conveys to the purchaser (lessee) the right to control the identified PP&E.

The right to control the use of the underlying PP&E is conveyed if any one of the following conditions is met while obtaining or controlling substantially all of the output of the facility:

a. The purchaser has the ability or right to operate the PP&E or direct others to operate the PP&E in a manner it determines;
b. The purchaser has the ability or right to control physical access to the underlying property, plant, or equipment; or
c. The price that the purchaser (lessee) will pay for the output is neither contractually fixed per unit of output nor equal to the current market price per unit of output at the time of delivery.

Depending on the pricing terms, the application of the standard to a PPA may involve significant judgment. Each individual scenario will have to be analyzed to determine whether pricing elements of the PPA enhance the sellers' ability to recover their fixed PP&E investment irrespective of the quantity of output from the facility and/or whether it otherwise appears to meet the definition of a lease.

Currently, leases are classified into two categories, operating leases or capital leases. Significant accounting challenges, such as those listed above, may be present for the Company if the PPA is determined to be a capital lease. A capital lease exists if any one of the following PPA attributes is present:

- Transfer of title to the assets to the power purchaser at the end of lease term
- Presence of a bargain purchase option for the assets
- Lease term is greater than or equal to 75% of the asset's estimated remaining useful life
- Present value of capacity and/or dispatchability payments (fixed payments) are greater than or equal to 90% of the asset's fair market value.

Credit Rating Agency Treatment of PPAs

In addition to the potential issues caused by PPAs that are classified as a capital leases, some credit rating agencies impute debt and interest expense for PPAs on the power purchaser's financial statements for the purposes of determining credit ratings. Therefore, even PPAs that are categorized as operating leases may have negative impacts on the company.

Lease Exposure Draft

A revised lease standard is expected to be introduced in the fourth quarter of 2011, with the effective date still to be determined, but estimated to be near 2015. The proposed lease standard requires that all leases be given financial statement recognition as lease assets and lease obligations.

Under the current version of the exposure draft and the most recent tentative decisions by the Boards (FASB - Financial Accounting Standards Board and IASB - International Accounting Standards Board), a lease is evident when:

- The fulfillment of the contract depends on the use of a specified asset; and
- The contract conveys the right to control the use of a specified asset for a period of time.
    - A contract would convey that right to control the use if the customer has the ability to direct the use, and receive the benefit from use, of the specified asset throughout the lease term.

Regarding the "use of a specified asset" criterion, a *system purchase* arrangement might not contain a lease if physically distinct portions of the generator's assets are not implied in the arrangement.

For a power purchaser, indicators of "control" might include control over:

1) How, when, and in what manner the power plant is used and/or
2) How the power plant is used in conjunction with other assets or resources to deliver the benefit from its use to the purchaser.

The principles contained in the exposure draft and tentative decisions by the Boards are subject to change until incorporated into a final standard. Current lease accounting guidance will remain in effect until the new pronouncement becomes effective, expected to take place in 2014 or 2015.

Derivatives and Hedging

ASC 815 "Derivatives and Hedging" provides the primary guidance in accounting for derivative transactions. Because energy purchase contracts often qualify as derivatives and these purchases are intended to provide for Public Service's normal operating obligations in serving retail and wholesale customers, it is important that these PPA contracts meet the requirements to be recognized under the Normal Purchase Normal Sale ("NPNS") exception.

Derivatives that do not qualify for the NPNS exception must be carried on the financial statements at fair value; absent a regulatory recovery mechanism, changes in the fair value of such derivatives may flow to the P&L and cause earnings volatility.

Contracts that have a price based on a formula or index that is not clearly and closely related to the asset being sold or purchased can not be considered NPNS exceptions. The analysis is specific to the contract being considered for the NPNS scope exception and may include identification of the components of the asset being sold or purchased.

The underlying or price determinate for the price adjustment is not considered clearly and closely related to the asset being sold or purchased in either of the following circumstances:

1. The underlying is extraneous (that is, irrelevant and not pertinent) to both the changes in the cost and the changes in the fair value of the asset being sold or purchased, including being extraneous to an ingredient or direct factor in the customary or specific production of that asset.
2. The underlying is not extraneous, but the magnitude and direction of the price adjustment are not consistent with the relevancy of the underlying. That is, the magnitude of the price adjustment based on the underlying is significantly disproportionate to the impact of the underlying on the fair value or cost of the asset being purchased or sold (or of an ingredient or direct factor, as appropriate).

In order to elect the NPNS exception, in addition to the requirements discussed above, the contract must also provide for the purchase or sale of something other than a financial instrument that is expected to be used by the entity over a reasonable period in the normal course of business.

<u>Summary</u>

The VIE accounting guidance requires Public Service to consider which activities have the most significant impact on an entity's financial performance, and who has the ability to direct those activities. Typically, if Public Service directs the most significant economic activities of an entity (if the entity is determined to be a VIE) it is the VIE's primary beneficiary, and Public Service is required to consolidate the VIE. This is an outcome that Public Service will avoid during negotiation of a PPA.

The determination of whether a PPA results in a lease is typically based on whether Public Service has the right to control the use of specified underlying PP&E, as determined by contract pricing and other factors. If a PPA contains a lease, the terms and conditions of the PPA will drive whether Public Service is required to record the PPA as a capital lease. Capitalization of lease assets and obligations, as required for capital leases, has negative impacts on financial metrics. Also, some credit rating agencies impute debt and interest expense for PPAs on the power purchaser's financial statements for the purposes of determining credit ratings. Therefore, even PPAs that are categorized as operating leases or PPAs that do not meet the base definition of a lease may have negative impacts on Public Service.

A revised lease standard is expected to be introduced in the fourth quarter of 2011 (and effective in approximately 2015) that would require that all transactions classified as leases be given financial statement recognition as lease assets and lease obligations. Based on the ongoing work and tentative decisions of the FASB and IASB, determination of whether an arrangement contains a lease may likely require a qualitative analysis of a purchaser's control over a specified asset. Depending on the guidance in the final standard, it's possible that certain types of PPA arrangements will no longer be considered leases. Public Service will assess PPAs during negotiation with the currently applicable standard. If Public Service knows the effective date of a new standard and that effective date occurs prior to the effective date of a PPA, Public Service will assess the PPA using the standard that will be in effect.

Regarding derivative considerations, certain pricing provisions may impact whether a PPA qualifies for the NPNS exception. Energy purchases that do not qualify for the NPNS exception must be carried on the financial statements of Public Service at fair value; absent a regulatory recovery mechanism, changes in the fair value of derivatives flow to Pubic Service's P&L and may cause earnings volatility. This is an outcome that Public Service will avoid during negotiation of a PPA.

Regional and National Transmission Initiatives

Since Public Service filed the 2007 Electric Resource Plan, the electric transmission industry experienced notable change. Events impacting electric transmission include 1) continued implementation the federal Energy Policy Act of 2005 ("EPAct 2005"); 2) implementation of the Federal Energy Regulatory Commission's ("FERC") latest open access transmission tariff rules, Order 890; and 3) efforts to expand the nation's transmission system to accommodate new renewable generation and to remedy chronic underinvestment in transmission, FERC Order 1000. While the Public Service system is relatively isolated within the Western interconnection, resource planning decisions are increasingly tied to national energy markets, policies and events. Below Public Service provides an overview of major industry trends and describes the larger context within which Public Service is planning for new energy supplies.

WestConnect

At this time, the only regions of the country that have not developed fully functional regional transmission organizations ("RTOs") are the west (outside of California) and portions of the southeast. Public Service participates in a voluntary organization known as WestConnect.[11] WestConnect was originally developed as an RTO; but, with the relaxation of federal pressure to form an RTO following the departure of former Chairman Pat Wood III from FERC, the WestConnect participants determined that forming an RTO was not in their collective interest. Rather, WestConnect evolved into a forum of 13 transmission-owning utilities in the states of Colorado, Wyoming, New Mexico, Arizona, Nevada and parts of California that work "collaboratively to assess stakeholder and market needs and develop cost-effective enhancements to the western wholesale electricity market."[12] All of WestConnect's meetings are open to the public and decisions are made by consensus. We discuss WestConnect's initiatives below.

Common OASIS

During the first several years of open access, each transmission provider developed its own Open Access Same Time Information System ("OASIS"), which then required customers to use multiple interfaces to procure and schedule transmission service. Working together and with a major energy market software developer, the wesTTrans.net common OASIS was established in 2004. WesTTrans.net is a single location where transmission customers can go to inquire about and purchase transmission service. WesTTrans has grown to include 31 transmission providers selling service on the site. Public Service's transmission function uses WesTTrans as its OASIS.

Regional Transmission Service

WestConnect developed a regional transmission pricing protocol that allows customers to purchase transmission service across two or more systems while paying only one, i.e., non-pancaked, wheeling rate. This project, which is hosted on the wesTTrans OASIS site, was initially established as a two-year experiment in 2009. Earlier this year, the participants made application to FERC to extend the project for an additional two years and FERC approved the application.

FERC Order 890 Implementation

Order 890 requires substantial new transmission planning activities and approval of each transmission provider's regional transmission planning and expansion activities. The WestConnect parties are jointly developing a common approach to regional planning that incorporates individual company planning efforts, sub-regional efforts such as the

[11] The WestConnect members are Public Service, Arizona Public Service, El Paso Electric, Imperial Irrigation District, NV Energy, Public Service Company of New Mexico, Sacramento Municipal Utility District, Salt River Project, Southwest Transmission Cooperative, Transmission Agency of Northern California, Tri-State, Tucson Electric Power Company and WAPA.

[12] WestConnect, WestConnect Internet Homepage, http://westconnect.com.

Colorado Coordinated Planning Group, and regional efforts managed through WestConnect.

Another Order 890 requirement was the establishment of business practices to implement conditional firm transmission service. Conditional firm transmission service is a product that can be sold where firm transmission service is not available during all hours of the year, with the customer accepting the right of the Transmission Provider to curtail schedules during certain conditions or agreed-upon number of hours each year. The WestConnect parties developed and posted a common business practice for this service in September 2007.

Efforts similar to WestConnect's are taking place in two other areas of the western United States. For example, the Bonneville Power Administration and a number of other northwest entities have created Columbia Grid. PacifiCorp, Idaho Power Company, Northwestern Energy and others have created a similar organization known as the Northern Tier Transmission Group. Those organizations perform much of the same function as WestConnect does for Public Service, yet neither is proposing to become a fully functional RTO.

In mid-2008, WestConnect, Columbia Grid and Northern Tier decided to join forces to pursue a number of projects that would benefit from a broader reach of expertise and geography. This "Joint Initiatives" group has developed a number of new products and services which are described below.

ACE Diversity Interchange ("ADI")
ADI involves the virtual consolidation of control areas to reduce the regulation requirements of each individual participant by combining all participants' regulation signals into one, thereby dampening the effects of load and generation variability. ADI is in limited operation today.

Intra-Hour Transmission Purchasing and Scheduling
One of the problems of operating in a non-RTO environment – that all sales and purchases of energy and transmission service take place in one hour increments – is exacerbated by the increasing penetration of variable energy resources in the region. The intra-hour product allows transmission customers to purchase and schedule transmission service on a sub-hourly basis. While not perfect, as RTO regions redispatch their systems on a 5 minute basis, a twice-hourly redispatch can help reduce individual utility balancing requirements. This product, which is actually an addition to the participants' transmission business practices, has been in place across much of the West since July 2011.

Dynamic Scheduling System ("DSS")
A "dynamic schedule" is used to transfer a load or a generator from one party to another. Because load and generation have variability, the primary purpose of entering into a transaction using a dynamic schedule is to transfer that variability from the seller to the buyer. The problem with dynamic schedules is they take weeks or even months to implement. DSS provides the ability to enter into a transaction needing dynamic schedules in a matter of minutes. The DSS tool has been in operation since March 2011.

Intra-Hour Transaction Accelerator Platform ("I-TAP")
This is a series of systems and tools that together will speed up and consolidate the steps needed to enter into a bilateral energy transaction in a non-RTO environment. I-TAP integrates instant messaging, OASIS and e-Tag functionality to support energy trades. The Joint Initiatives participants are working with the software developer to test the system, and we expect it to be ready for operation in late 2011.

Energy Imbalance Market ("EIM")
Over the past two years, Public Service has taken a leadership role in a major initiative to promote and help develop a real-time centrally-dispatched energy market in the western interconnection. The EIM is modeled after the existing "Energy Imbalance Service" market in operation in the Southwest Power Pool ("SPP"). Southwestern Public Service Company has operated within the SPP Energy Imbalance Service market since its inception in 2007 and has enjoyed significant benefits of reduced production costs and variable resource integration. The western EIM, like SPP's, will reduce overall production costs by taking offers from generators and dispatching the most efficient generators first, thereby reducing overall costs. The EIM system of tools will calculate the least cost generation dispatch every five minutes while respecting the limits of the interconnected transmission system. The primary difference between the EIM and the EIS is that the EIM will operate without an RTO. Instead, an independent market operator will be established to run the market, along with a yet to be determined board oversight, and with a market monitor to detect and eliminate market abuse.

The Western Electricity Coordinating Council ("WECC") is heavily involved in the EIM development, and in June released the results of a benefit-cost study of the market. This study showed a mid-point of benefits of approximately $141 million per year. The costs of the implementing and operating the market were in a fairly wide range, which is indicative of the lack, to date, of a consensus agreement on the market's function and scope. Upon release of this analysis, the

WECC Board of Directors directed its staff to work through the WECC committee process to develop a high level functional specification as well as perform an analysis on what it would mean for WECC to be the market operator, or to have a third party operate the EIM. These assessments were completed for the September WECC Board meetings. During discussion at the board meeting, the Board passed a resolution directing the staff to prior to the December Board meeting 1) investigate potential funding sources to develop an RFP-quality market design specification; 2) hold meetings with FERC staff concerning funding and organizational options; 3) issue an RFI to determine interest, cost and schedule for a third-party facilitator; and 4) evaluate the feasibility of and develop a plan for sharing operational data with a third party market operator.

WestConnect is working to educate its members and analyze the EIM components in a work group that is led by Public Service. This work group has met regularly over the past 1½ years and has been a forum for education and consensus building on what the WestConnect members would like to see in an EIM. The work group also informs the WestConnect Steering Committee of its activities and solicits input and direction from the Steering Committee. It is also expected that this work group will play a role in the development and/or review of the functional specifications and tariff language that will result from continued development of the EIM.

Public Service is optimistic that the EIM will come to fruition. We believe, as has been our experience in both the SPP and Midwest ISO markets, that a centrally-dispatched market in the west will provide the following significant benefits: (1) it will improve reliability, particularly during generation and transmission outages, by immediately redispatching the system to offset such generation or transmission shortages; (2) it will lower production costs by dispatching the most efficient mix of generation while respecting transmission limitations; (3) it will provide the operational support and resultant cost savings for the challenges associated with the integration of large amounts of variable energy resources; and (4) it will provide for a more optimal use of the transmission system by allowing power to flow up to – or at least closer to – transmission limits while still maintaining reliability.

Mandatory Reliability

One component of EPAct 2005 was the establishment of mandatory reliability standards. EPAct 2005 authorized FERC to designate an Electric Reliability Organization ("ERO"). FERC approved the North American Electric Reliability Council ("NERC") as the ERO. NERC, as the ERO, then delegated specific components of its compliance monitoring and enforcement authority to eight Regional Entities ("RE"). The RE for the state of Colorado is WECC.

The ERO and REs develop, through an ANSI-approved process, reliability standards that are filed for FERC approval. Once these standards are approved by FERC, they are enforceable with the potential for penalties up to $1 million per day, per violation. There are several sections to each approved standard, including requirements, measures and compliance sections. The requirements set out what is required, the measures explain what evidence an entity is expected to have to demonstrate compliance, and the compliance section addresses the consequences for failing to meet the requirements.

At this time, 113 reliability standards are in effect, mandatory and enforceable in the United States. 103 of these apply to Public Service and involve a wide range of activities including vegetation management, short and long-term planning, normal and emergency operations, sabotage reporting, and cyber and physical protection. In FERC Order No. 693, which approved the initial 83 standards, FERC issued a substantial list of directives, requiring that most of the standards be modified to improve clarity and enforceability. On a priority basis, NERC and industry volunteers have been working diligently to modify the standards, to address these directives, and numerous others that have been issued since.

A significant task for the industry is to develop and retain documentation that demonstrates its compliance activities, along with documenting how compliance with each of the standards is accomplished. This is a very time-consuming and resource intensive process. Entities must also monitor standards as they are frequently modified or created, in order to ensure the appropriate compliance activities are implemented and documented timely.

<u>FERC Order No. 1000</u>

On July 21, 2011 FERC issued the Final Rule in its Notice of Proposed Rulemaking regarding transmission planning and cost allocation. Titled Order No. 1000, the Final Rule promulgated several modifications and requirements regarding regional transmission planning, interregional transmission planning, and the cost allocation methodologies associated with each of these. In addition, FERC took steps to introduce competition into the construction and ownership of transmission projects by requiring removal of so-called rights of first refusal to build transmission projects.

Transmission Planning

In its Final Rule, the Commission requires each public utility transmission provider to participate in a regional transmission planning process that has a cost allocation methodology associated with it. Projects that are selected in the regional plan and found to have broad benefits will be required to have a cost allocation methodology associated with their approval. The only restriction FERC placed on the definition of a region is that it must be more than one public utility transmission provider, e.g., Public Service cannot be its own region.

Order No. 1000 also requires each region (for purposes of transmission planning) to coordinate with each neighboring region to develop an interregional transmission planning and cost allocation construct. This construct requires that neighboring regions identify facilities that result in a more efficient delivery of energy to entities in both regions. Similar to the regional transmission planning requirements, the interregional transmission planning processes must also have a cost allocation methodology associated with them. Each region must agree to accept cost allocation for a project before its cost can be allocated to more than one region.

Cost Allocation

FERC identified six cost allocation principles for regional cost allocation methodologies and six similar cost allocation principles for interregional cost allocation methodologies. These principles are:

1. Costs must be allocated at least roughly commensurate with estimated benefits;
2. Those who do not benefit from transmission are not to be allocated cost;
3. Benefit-to-cost thresholds must not be so high as to exclude projects with significant net benefits from regional cost allocation;
4. No allocation of costs outside a region unless the other region agrees;
5. Cost allocation methods and the process for identifying beneficiaries must be transparent;
6. Different allocation methods may apply to different types of facilities.

Notably, FERC leaves significant deference to the regions to develop cost allocation methodologies that have the support of stakeholders in each region.

Rights of First Refusal

Finally, Order No. 1000 requires the removal of rights of first refusal from all federal tariffs and agreements. In its place, non-incumbent transmission developers must be given equal opportunity to participate in the planning process, including the opportunity to be chosen to construct transmission projects selected in a regional plan for purposes of cost allocation.

Notably, there are four exceptions for which incumbent transmission providers retain the right of first refusal:

1. Projects not selected in a regional transmission plan for purposes of cost allocation;
2. Upgrades of existing transmission facilities;
3. Competitive bidding is allowed but not required;
4. Any state or local laws or regulations that govern who can construct transmission facilities are not affected by the Final Rule.

Compliance Efforts

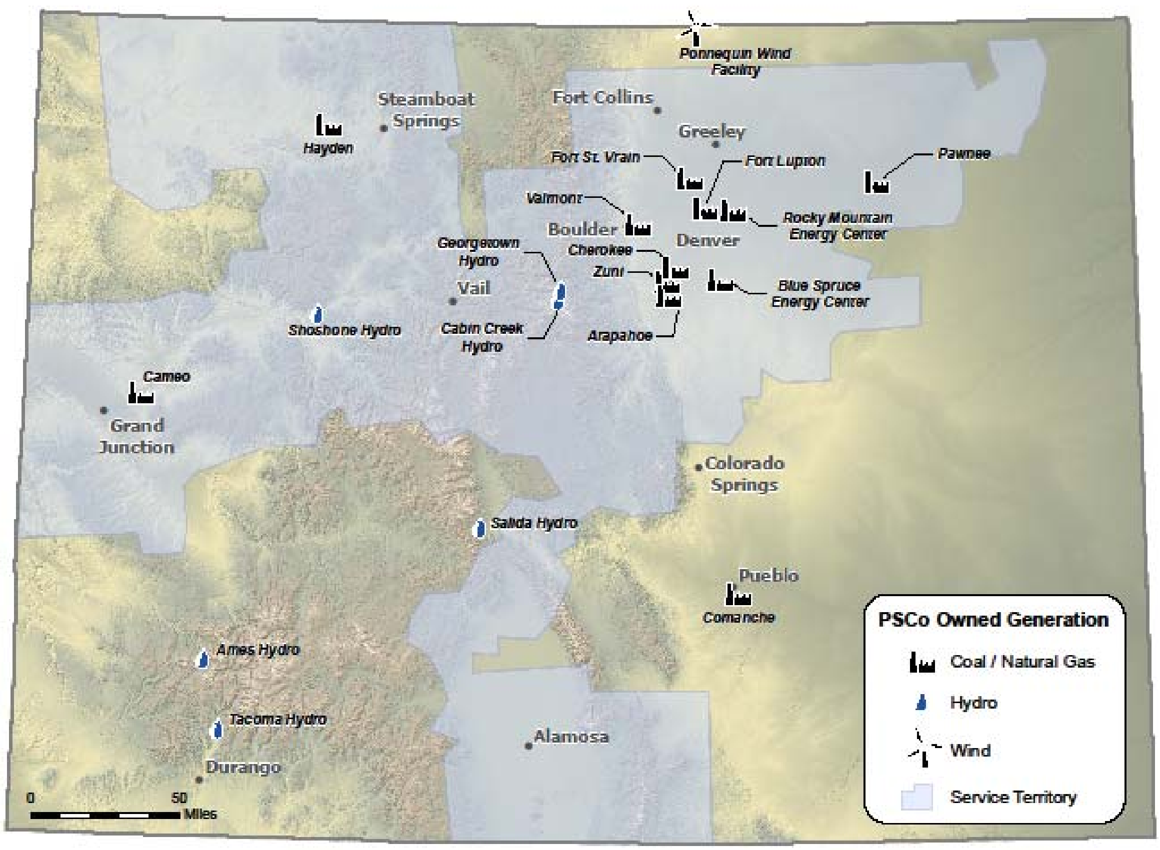
All public utility transmission providers have until October 11, 2012 to conduct stakeholder processes and develop their compliance filings related to regional transmission planning and cost allocation; the regions have until April 11, 2013 to conduct stakeholder processes and develop their compliance filings related to interregional transmission planning and cost allocation.

2.3 PUBLIC SERVICE OVERVIEW

Service Territory

Public Service, an operating company of Xcel Energy Inc., is an investor-owned utility serving approximately 1.4 million electric customers and 1.3 million gas customers in the state of Colorado. The Company serves approximately 75% of the state's population. Public Service's electric system is summer peaking with a 2011 peak customer demand of 6,604 MW and total annual energy sales of approximately 36,206 GWh (2010). Figure 2.3-1 illustrates the Company's service territory along with the general location of the Company's owned electric generating facilities.[13]

Figure 2.3-1 Service Territory

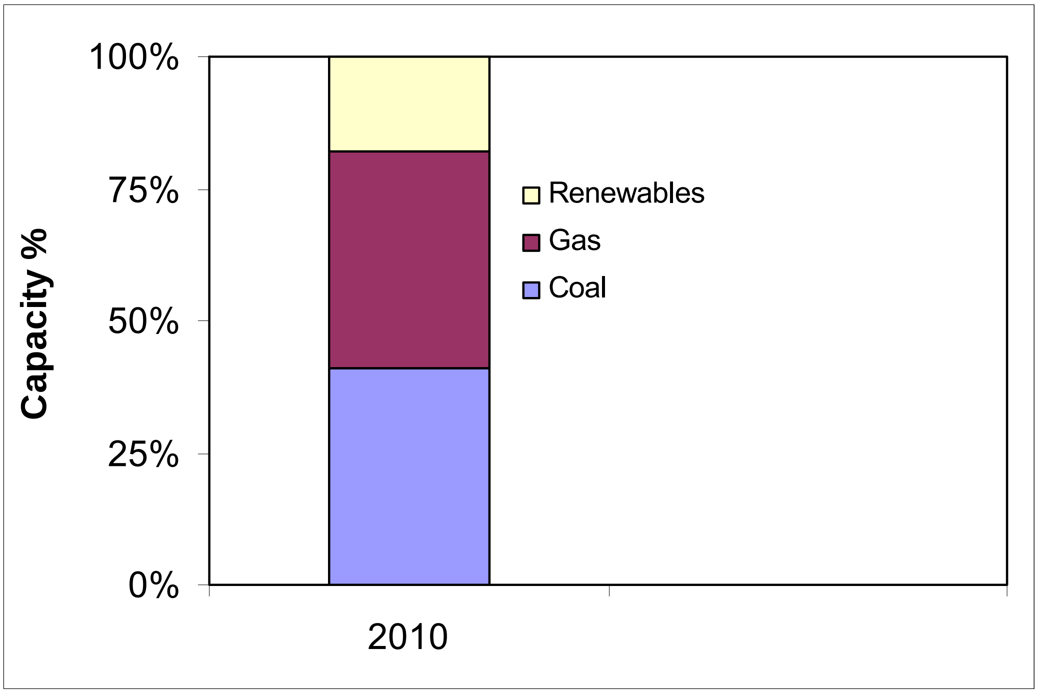


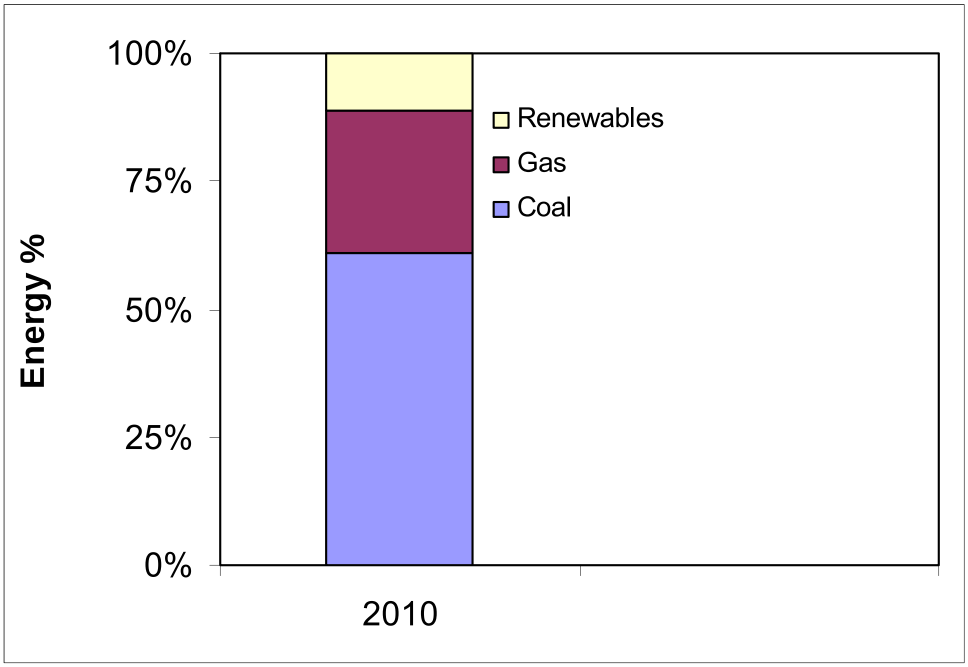
[13] Public Service serves the areas around Longmont and Fort Collins but does not provide electric service in those cities. The Craig 1 and 2 coal-fired generation resources and the Alamosa CTs are not shown.

Existing Public Service Generation Supply Mix

Figure 2.3-2 illustrates the makeup of generating capacity and energy on the Public Service system in 2010, including the capacity and energy that Public Service purchases from other utilities and independent power producers. This figure does not include any additional resources Public Service plans to add to its system through the 2011 ERP.

Figure 2.3-2 Public Service 2010 Capacity and Energy Mix





Overview of the 2007 ERP

Public Service filed its 2007 ERP with the Commission in November 2007. The Company selected a portfolio of resources that, as approved and modified by the Commission in CPUC Decision No. C09-1257 (November 6, 2009), included the following resources which are projected to meet the Company's resource needs through 2015:

- The purchase by Public Service of approximately 900 MW (the two resources were listed as having a combined winter rating of 921 MW) of existing gas-fired resource capacity;
- PPAs for 701 MW of new wind resource capacity;
- A PPA for 250 MW of solar thermal with thermal storage resource capacity; and
- PPAs for 105 MW of solar photovoltaic resource capacity.

Subsequent to Commission approval of the above resources the Company requested to amend the 2007 ERP to: 1) acquire the gas-fired resources earlier than the date specified in the selected bid; 2) defer consideration of the acquisition of the 250 W solar thermal with thermal storage resource and the last 45 MW of the 105 MW of solar photovoltaic resource to the 2011 ERP; and 3) hold a solicitation to select a new wind project to replace the selected project for the last 201 MW of the 701 MW of approved wind resources. The Commission approved these requests in CPUC Decision Nos. C10-1196 (November 4, 2010) and C11-0509 (May 11, 2011).

The Company added the resources in Table 2.3-1 pursuant to the 2007 ERP.

Table 2.3-1 Resources Added Through 2007 ERP (MW)

Facility	2010	2011	2012
Rocky Mountain Energy Center (1)	601		
Blue Spruce Energy Center (1)	278		
Cedar Creek II Wind (2)		250	
Cedar Point Wind (2)		252	
Limon Wind (2)			201
Cogentrix of Alamosa (2)			30
San Luis Solar (2)			30

(1) Current Summer capacity rating
(2) Nameplate capacity rating

The status of purchasing or contracting for the resources listed in Table 2.3-1 is as follows:

Purchase of Rocky Mountain Energy Center and Blue Spruce Energy Center
Public Service purchased the existing Rocky Mountain and Blue Spruce Energy Centers gas-fired generation resources from Calpine Corporation on 12/6/10.

Cedar Creek II PPA
Public Service executed a PPA for this wind resource on 5/19/10. The resource is essentially constructed and generating test energy. Public Service expects the resource to achieve commercial operation in October 2011.

Cedar Point PPA
Public Service executed a PPA for this wind resource on 3/29/2010. The resource is partially constructed and generating test energy. Public Service expects the resource to achieve commercial operation in November 2011.

Limon PPA
Public Service executed a PPA for this wind resource on 4/22/2011. The resource has started construction. Public Service expects the resource to achieve commercial operation in the fourth quarter of 2012.

Cogentrix of Alamosa PPA
Public Service executed a PPA for this solar PV resource on 6/23/2010. The resource is partially constructed. Public Service expects the resource to achieve commercial operation in the first quarter of 2012.

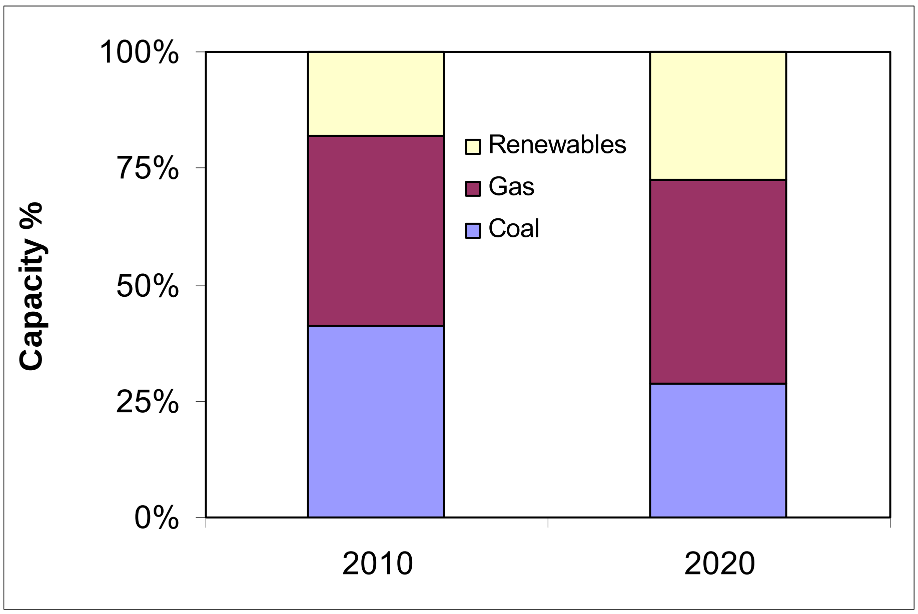
San Luis Solar PPA

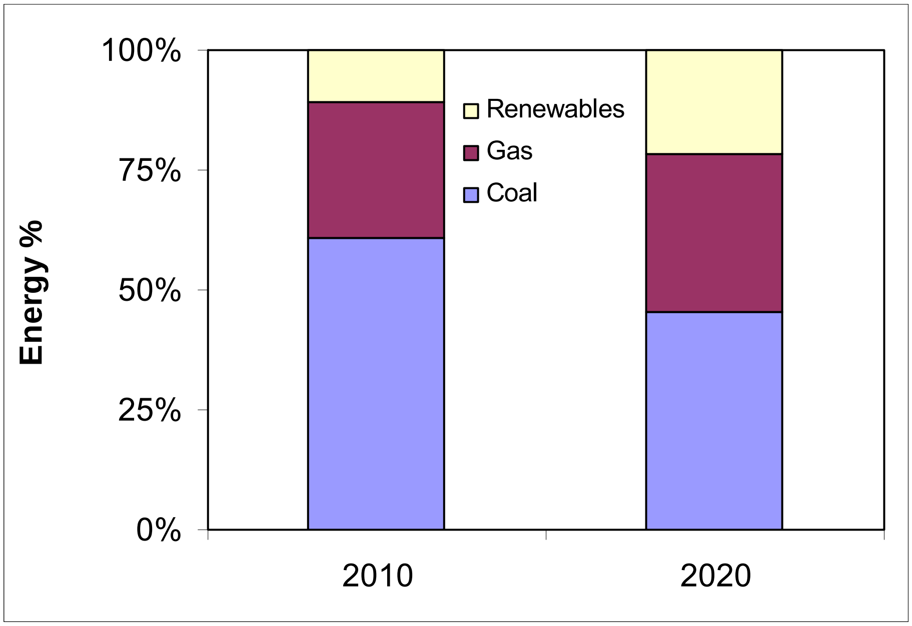
Public Service executed a PPA for this solar PV resource on 8/10/2010. The resource is partially constructed. Public Service expects the resource to achieve commercial operation in the fourth quarter of 2011.

2020 Public Service Generation Supply Mix

The resources acquired through the 2007 ERP will change the capacity and energy mix of the Public Service system. Figure 2.3-3 shows the anticipated makeup of generating capacity and energy for the Public Service system in 2020 versus 2010. The 2020 generating capacity and energy include generic expansion resources.

Figure 2.3-3 Public Service 2020 Capacity and Energy Mix





Colorado Transmission Planning Initiatives

Transmission Planning Rule 3627

Prior to the Commission issuing its decision in its 20-year transmission rule Notice of Proposed Rulemaking ("NOPR"), Docket No. 10R-526E, there were no formal rules requiring transmission providers to develop and file long-range, 10-year and conceptual 20-year, plans with the Commission. Prior to that time, Public Service developed ten-year transmission plans to meet its internal planning needs. With the implementation of Transmission Planning Rule 3627, the following changes occurred in the Company's regulatory reporting requirements with respect to transmission planning:

- Public Service must file both 10-year transmission plans and 20-year conceptual plans on a biennial basis. The plans should be jointly coordinated with other transmission providers in the state in a manner that is consistent with a single system planning concept, i.e., as if the entire statewide transmission system were owned by a single entity. Such plans will be filed with the Commission on a biennial basis on February 1 in the even years;
- The plans must include all proposed transmission facilities of 100 kV or larger;
- Public Service must develop and implement a public stakeholder process that actively solicits public participation in the development of the Company's transmission plans, and to facilitate the public review of those plans by both the jurisdictional governments and public sectors that might be impacted by a particular transmission project. The Company is

required to provide a summary of stakeholder participation and input, and how such input was incorporated into the plans;

- Public Service is required to provide copies of the filed plans to government agencies and other stakeholders who participated in the planning process. The Company is also required to provide public access to all of the studies, reports assumptions, load forecasts, methodologies and other information used to prepare the plans by means of a Company website or other publically accessible website. The information must remain available until the filing of the next biennial plans;
- Finally the Company is required to participate in public workshops held by the Commission to review the plans and supporting information.

For the 2012 plan, only a ten-year plan is required. This is because, following Commission approval of the final rule, there was not ample time to develop both the ten-year and 20-year plans.

Facilities Rule 3206

On December 17, 2009, the Commission issued a NOPR in Docket No. 09R-904E for the purpose of revising the current rules related to Construction or Extension of Electric Facilities, Rule 3206. The first Rule 3206 Report filed by Public Service under the new rules was filed with the Commission on May 2, 2011. The Company sought and received any needed waivers to the rule during the period between the Rule 3206 filing and the filing of the long-term transmission plan.

2.4 EVALUATION OF EXISTING RESOURCES

Company Owned Resources

Public Service currently owns 5,376 MW (summer rating) of electric generation facilities, but several of these owned facilities are scheduled for retirement during the RAP, primarily as a result of the Clean Air- Clean Jobs Act emissions reduction plan. Public Service wholly owns these facilities, with the exception of the Hayden and Craig plants, which are jointly owned by Public Service and other utilities. Table 2.4.1 shows the expected retirements and additions of Public Service-owned electric generation resources during the RAP.

Table 2.4-1 Public Service Owned Generation Facilities (MW)

	2012	2013	2014	2015	2016	2017	2018
Installed Net Dependable Capability	5,376	5,376	5,376	5,376	5,376	5,376	5,376
Retirements							
Arapahoe 3			(44)	(44)	(44)	(44)	(44)
Cherokee 1	(107)	(107)	(107)	(107)	(107)	(107)	(107)
Cherokee 2	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Cherokee 3					(152)	(152)	(152)
Valmont 5							(184)
Zuni 2				(65)	(65)	(65)	(65)
Additions							
Cherokee 2X1					569	569	569
Total	5,163	5,163	5,119	5,054	5,471	5,471	5,287

Please see Attachments 2.4-1, 2.4-2, 2.4-3, 2.4-4 and 2.4-5 provided at the end of Section 2.4 for a more detailed accounting of the Company's owned generation resources including facility name and location, capacity rating, estimated remaining useful life and capacity factor information.

An analysis of the resource type for the Company's owned electric generation facilities is contained in Table 2.4-2. The coal-fired figures for 2012 include the retirement of Cherokee 1 and Cherokee 2.

Table 2.4-2 Public Service Owned Generation Facilities

Generation Fuel	2011 Net Dependable Summer Capacity (MW)	% of Total Owned Generation	2012 Net Dependable Summer Capacity (MW)	% of Total Owned Generation
Coal-fired	3,050	57%	2,837	55%
Gas-fired	2,087	39%	2,087	40%
Wind (1)	3.2	0.0%	3.2	0.0%
Hydro/Pumped Storage	236.3	4%	236.3	5%
Total	**5,376**	**100%**	**5,163**	**100%**

(1) Wind Capacity equivalent to 12.5 % of 26.7 MW of Nameplate Capacity

<u>Purchased Power</u>

Public Service buys a significant amount of firm capacity and energy through PPAs with various agreement term lengths and fuel resource types. These PPAs contain provisions that detail the amount and type of capacity available to Public Service. Some are "unit contingent," meaning that the delivered capacity is contingent upon the availability of certain generating facilities. If one of these facilities is not available for operation, the supplying counterparty can reduce the amount of capacity provided to Public Service. Table 2.4-3 lists the summer rated capability totals for the PPAs at levels above and below 10 MW and the overall PPA generation resource total. The total PPA generation resource includes the retail DG, wholesale DG and Non-DG eligible energy resources.

Table 2.4-3 PPA Generation Resource (MW)

	2012	2013	2014	2015	2016	2017	2018
PPAs > 10 MW	2,317	2,129	2,064	2,090	1,686	1,504	1,504
PPAs < 10 MW	91	102	114	126	136	148	149
Total	2,408	2,230	2,178	2,216	1,822	1,651	1,653

Note: Total Row differs from sum of resource rows for 2013 and 2017 due to rounding.

Table 2.4-4 lists the summer rated capability that Public Service expects to receive from these contracts from 2012 through 2018. Table 2.4-5 lists the summer rated capability that Public Service expects to receive from contracts that provide less than 10 MWs from 2012 through 2018. For planning purposes, Public Service assumes that the purchase of capacity will cease at the PPA expiration date and future contracted purchases that are not yet commercial will achieve operation as planned. Please see Attachment 2.4-6 provided at the end of Section 2.4 for the following additional information: 1) duration of the contracts; and 2) contract provisions that allow for modification of the capacity and energy provided. Table 2.4-6 classifies these purchases by fuel type.

Table 2.4-4 PPA Summer Capacity

PPA	2012	2013	2014	2015	2016	2017	2018
Basin 1	100	100	100	100	0	0	0
Basin 2	75	75	75	75	0	0	0
Brush 1 & 3	78	78	78	78	78	0	0
Brush 4D	133	133	133	133	133	133	133
Cedar Creek Wind (1)	38	38	38	38	38	38	38
Cedar Creek Wind II (1)	31	31	31	31	31	31	31
Cedar Point Wind (1)	32	32	32	32	32	32	32
Cogentrix of Alamosa (2)	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Colorado Green (1)	20	20	20	20	20	20	20
Fountain Valley	243	0	0	0	0	0	0
Greater Sandhill , LLC (3)	9.4	9.4	9.4	9.4	9.4	9.4	9.4
Limon Wind LLC (1)	0	25	25	25	25	25	25
Limon Wind II LLC (1)	0	25	25	25	25	25	25
Logan Wind (1)	25	25	25	25	25	25	25
ManChief	258	258	258	258	258	258	258
Northern Col I & II (1)	22	22	22	22	22	22	22
PacifiCorp (w/reserves)	150	150	150	176	176	176	176
Peetz Table (1)	25	25	25	25	25	25	25
Plains End	221	221	221	221	221	221	221
Ridge Crest Wind (1)	4	4	4	4	4	0	0
San Luis Solar (2)	16.6	16.6	16.6	16.6	16.6	16.6	16.6
Spindle Hill CT	284	284	284	284	284	284	284
Southwest Arapahoe	121	0	0	0	0	0	0
Southwest Valmont	78	0	0	0	0	0	0
Spring Canyon (1)	8	8	8	8	8	8	8
Thermo Cogen	129	129	129	129	129	129	129
Thermo UNC	65	65	0	0	0	0	0
Tri-State 2	100	100	100	100	100	0	0
Tri-State 3	25	25	25	25	0	0	0
Tri-State Brighton	0	136	136	136	0	0	0
Tri-State Limon	0	68	68	68	0	0	0
Twin Buttes (1)	9	9	9	9	9	9	9

(1) Wind capacity rated at 12.5% of nameplate capacity.
(2) Solar capacity rated at 55.3% of nameplate AC capacity.
(3) Solar capacity rated at 47% of nameplate DC capacity.

Table 2.4-5 PPA Summer Capacity - Under 10 MW

Purchase Power Contract	2012	2013	2014	2015	2016	2017	2018
Amonix SolarTAC 1, LLC (2)	0.3	0.3	0.3	0.3	0.0	0.0	0.0
Boulder Silverlake	3.0	3.0	3.0	3.0	3.0	3.0	0.0
Boulder Betasso	3.1	3.1	3.1	3.1	3.1	3.1	0.0
Boulder Kohler	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Boulder Lakewood	3.1	3.1	3.1	3.1	3.1	3.1	0.0
Boulder Maxwell	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Boulder Orodell	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Boulder Sunshine	0.8	0.8	0.8	0.8	0.8	0.8	0.0
Denver Water - Dillon Dam	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Denver Water - Foothills Water Treatment	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Denver Water - Gross Reservoir	8.1	8.1	8.1	8.1	8.1	8.1	8.1
Denver Water - Hillcrest Hydroelectric	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Denver Water - Roberts Tunnel	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Denver Water - Strontia Springs Dam	1.1	1.1	1.1	1.1	1.1	1.1	1.1
NREL/DOE (NWTC) (1)	0.5	0.5	0.5	0.5	0.0	0.0	0.0
NREL's NWTC, ALSTOM Power, Inc (1)	0.4	0.4	0.4	0.4	0.0	0.0	0.0
On-Site PV	44.9	58.4	71.4	83.7	95.3	106.8	118.3
Palisade Hydro	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Ponnequin I (aka Distributed Generation Systems) (1)	0.7	0.0	0.0	0.0	0.0	0.0	0.0
Redlands Water & Power	0.6	0.6	0.0	0.0	0.0	0.0	0.0
Siemens Energy, Inc (1)	0.3	0.3	0.3	0.3	0.0	0.0	0.0
Stagecoach (Upper Yampa Conservancy Dist)	0.4	0.4	0.4	0.4	0.4	0.4	0.4
STS Hydro - Mt. Elbert	2.5	0.0	0.0	0.0	0.0	0.0	0.0
SunE Alamosa (2)	3.8	3.8	3.8	3.8	3.8	3.8	3.8
WM Renewable Energy	3.3	3.3	3.3	3.3	3.3	3.3	3.3

(1) Wind capacity rated at 12.5% of nameplate capacity.
(2) Solar capacity rated at 47% of nameplate DC capacity.

Table 2.4-6 Purchase Power Capacity by Fuel Type (2012)

Fuel Type	Summer Capacity (MW Capacity Credit)	Percent of Total
Coal	300	12.4%
Natural Gas	1,610	66.9%
Hydro	37.1	1.5%
Biomass	3.3	0.1%
Solar (2)	111	3.8%
Wind (1)	215.9	9.0%
System	150	6.2%

(1) Wind capacity rated at 12.5% of nameplate capacity.
(2) Solar capacity rated at 47% of nameplate DC capacity or 55% of AC capacity.

Water Resources

Background

Understanding Colorado water law is essential to understanding Public Service's water supply and its ability to supply water reliably and affordably, both now and in the future. Colorado water law is built on four principal tenets (Citizen's Guide to Colorado Water Law, 2nd Edition, 2004):

1. All ground and surface water is a public resource for beneficial use.
2. A water right is the right to use a portion of the water resource.
3. Water right owners may build facilities to divert and convey water on lands owned by others.
4. Water right owners may use streams and aquifers to convey and store water.

Water rights are defined by several characteristics:

1. Type of beneficial use
2. Place of use
3. Location of diversion
4. Diversion amount or rate

These characteristics define the water rights effect on the water supply, the amount of water consumptively used and removed from the system, and the effect on other water rights in the basin. Water rights are administered according to the Prior Appropriation Doctrine, often shortened to "first in time, first in right", which holds that water rights put to beneficial use first, i.e. senior water rights, are entitled to their full appropriation before subsequently-appropriated water rights, i.e., junior water rights, can divert any water. Using this concept, all the physically-available water in the State is allocated, in priority, until the supply is exhausted.

Under this resource allocation approach, there is no fee to use water, but there are typically operations and maintenance costs associated with the diversion, measurement, and conveyance of water to beneficial use. The beneficial use of water proscribed by the water rights decree is a real property right and can be changed to allow alternate water uses, diversion locations, and use locations, allowing transfers to occur readily, subject to demonstration of non-injury to other water rights in the basin and decree of the Water Court.

Water Courts preside over water rights decrees, changes, and disputes. The Division of Natural Resources, through the offices of State and Division Engineers, administer allocation of water to water rights in priority. Colorado water law and administration is built on a complex history of administrative and legal practices dating back to 1861. Please refer to the following resources for additional information about Colorado water law and water rights administration:

- Citizens Guide to Colorado Water Law, 2nd Edition, Colorado Foundation for Water Education, 2004. (http://www.courts.state.co.us/userfiles/File/Media/Law_School/cfweCitizenGuideColoradoWaterLaw2Edition.pdf).
- *Acquiring, Using and Protecting Water in Colorado*, 2nd Edition, Trout, Raley, Montano, Witwer and Freeman, P.C., 2004.
- Colorado Water Rights Fact Sheet (http://www.blm.gov/nstc/WaterLaws/colorado.html)

Use of Water in Electric Generation

Water is consumed during electric generation in a variety of ways:

1. Steam/water cycle. Steam generation is typically a closed-loop system, but boiler feed make-up water is required to replace minor losses.
2. Circulating water cooling. Circulating water is used to cool steam in the steam/water cycle. Circulating water is evaporatively-cooled in the cooling towers and reused until its water quality is no longer suitable. Blowdown rejected from the cooling tower is treated prior to discharge or stored and evaporated, depending on plant design. Cooling typically drives the vast majority of plant water usage and consumption.
3. Other usage. Relatively small volumes of water are used in a number of other important plant capacities, such as dust suppression, fire control, bottom ash removal, and emissions control.
4. Hydro-electric generation. Water consumed is through evaporation while stored in reservoirs at Public Service-owned hydropower facilities in Colorado.

The resources cited below provide additional discussion of the usage of water for power generation activities:

- General Thermal power station water usage (http://en.wikipedia.org/wiki/Thermal_power_station)
- Cooling tower water usage (http://en.wikipedia.org/wiki/Cooling_tower)
- *Water & Sustainability (Volume 3): U.S. Water Consumption for Power Production – The Next Half Century*, Electric Power Research Institute, 2002.

Public Service's Water Resources

Public Service has acquired a wide variety of water rights and contracts to support electric generation operations. See Table 2.4-7. All of Public Service's water rights are decreed for uses appropriate for electric generation and use at plants, and have been developed in three principal ways:

- Appropriation by Public Service.
- Acquisition and change of use of previously-appropriated water rights, including wholly-owned ditch or reservoir companies.
- Supply provided by third-party based on pro-rata ownership of water right, i.e. independently-operating ditch companies or Colorado-Big Thompson Project units.

Public Service has also acquired an extensive portfolio of contracted water supplies through leases with a variety of municipal, agricultural, and industrial entities (Table 2.4-8).

Table 2.4-7 Summary of Public Service Water Rights Portfolio

Water Right Type	Description
Senior direct-flow	Water obtained by direct diversion from watercourse. In-priority during most years.
Junior direct-flow	Water obtained by direct diversion from watercourse. Limited availability during most years.
Conditional direct-flow	Water right not yet exercised. When exercised and made absolute, will become junior direct-flow right.
Senior storage	Water stored for use, as-needed. Reservoir yield adequate during most years.
Junior storage	Water stored for use, as-needed. Reservoir yield limited during most years.
Conditional storage	Storage right not yet exercised. When exercised and made absolute, will become junior storage.
Exchange	Decreed ability to remove water upstream while replacing water above the calling downstream right.
Junior Recharge	Water placed into the alluvial aquifer which then accretes to the river over time.
Colorado-Big Thompson units	Trans-basin water from the Colorado River basin delivered to the Front Range and deliverable within Northern Colorado Water Conservancy District boundaries. Can be stored or used directly.
Augmentation	Decreed right to replace out-of-priority stream depletions with other in-priority supplies.
Groundwater	Water withdrawn from the alluvial or Denver Basin aquifer. Augmentation plan required to prevent injury to other water rights holders (alluvial aquifer).

Table 2.4-8 Summary of Public Service Water Contract Portfolio

Contract or Account Type	Description
Municipal – potable	Treated water provided through municipal distribution system.
Municipal – raw water	Raw water from municipal portfolio. May be either native or trans-basin supply.
Municipal – recycled water	Reusable treated sewage effluent.
Municipal – effluent trade	Trade of Public Service-owned water rights for an equivalent volume of reusable effluent or raw water
Agricultural – recharge credits	Recharge credits (see above) generated by the Junior water rights and recharge facilities of an agricultural entity.
Agricultural – off-season storage	The ability to store water in an agricultural reservoir during the late summer, fall, and winter when agricultural water has been vacated.
Agricultural – interruptible/as-needed	Agricultural water rights which have been decreed for temporary or episodic industrial use.
Industrial – supplemental water supply	Water supplied from the portfolio of another industrial user.

Public Service has invested in the integration of its water supplies, particularly in the South Platte, Arkansas, and Yampa River basins. Water supply integration is typically accomplished through designation of multiple sources of supply, points of diversion (movement of water downstream), and exchanges (movement of water upstream). Water supply integration within a basin allows water to be moved in-priority to meet plant needs and promotes the most efficient usage of Public Service's water rights portfolio.

Public Service has entered into a number of water supply agreements which offer significant benefits to the participants. A summary of selected contract benefits includes:

1. Contracts for raw water or reusable effluent for use in power generation allow municipalities to generate revenue from existing excess reusable water supplies for use in infrastructure development or maintenance, portfolio development, or other purposes, while increasing Public Service's overall water supply and system reliability through access to municipalities' water rights portfolio and/or trans-basin water supplies.
2. Trades with municipalities for equivalent quantities of fully-reusable water from other sources, including treatment plant effluent, allow municipalities to benefit from higher quality water for use as municipal supply, while Public Service benefits from having a year-round water source available on an as-needed basis.
3. Water supply contracts with agricultural entities, particularly as-needed storage and recharge credit agreements, allow agricultural entities to financially benefit from excess capacity/supply in their systems. Public Service increases its water supply reliability, as-needed, while avoiding significant capital expenditure and risk associated with developing equivalent facilities.
4. Interruptible, as-needed drought protection is afforded through agreements in which farmers will temporarily dry-up farmland during significant drought when limited water supply threatens crop viability, and deliver that water to industrial use (long-term version of an interruptible water supply agreement, definition provided by 37-92-309 C.R.S.). This contract provides annual maintenance payments and delivery payments during drought, improving the viability of the agricultural entity. As a result, Public Service foregoes excess senior water right acquisitions which would be required to supply a firm drought yield. Foregoing these expenses not only saves Public Service capital cost and risk, but also minimizes the acquisition and permanent dry-up of irrigated agriculture in the state.

Public Service's Colorado Water Resource Costs

Under Colorado water law there is no cost for water diverted to beneficial use under a water right decree. Costs are typically associated with operation and maintenance of water diversion and distribution systems. Public Service maintains a variety of water diversions, storage, and conveyances, including diversion dams, ditches, pump stations, and reservoirs. Many of these facilities have been in existence and operating for over 100 years and have relatively low annual costs, often collected as shareholder assessments. Newer facilities, such as pump stations, are operated and maintained as a part of normal plant functions and are relatively low cost.

Contracted water supply cost escalation typically follows one of three forms:

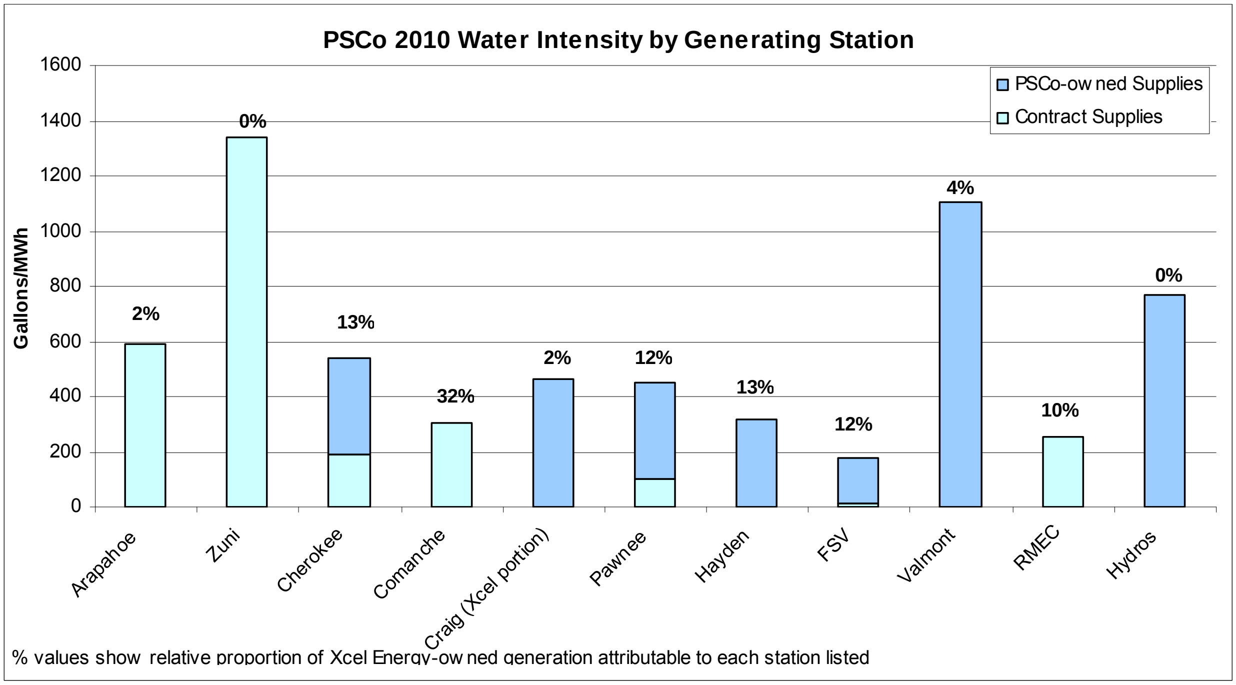
1. Maximum fixed percentage increase, i.e. 5 percent annually.
2. Initial water lease cost with an escalation term indexed to the Consumer Price Index.
3. Water unit cost set annually by the leasing entity's Board of Directors, in accordance with the entity's rate-setting practices.

Public Service's Water Consumption and Intensity

Attachment 2.4-7 at the end of Section 2.4 shows the 2010 consumption figures for the Public Service system.

Figure 2.4-1 shows the water intensity for Public Service-owned generation stations and the relative proportion of water supplied through self-owned and contracted water supplies. Generally, self-supplied water is the least expensive and future costs are expected to remain stable, in accordance with operations and maintenance needs. Contracted water supply costs are anticipated to increase inline with regional water costs, but afford plants the reliability and firm yields associated with larger municipal water purveyors.

Figure 2.4-1 Water Intensity



Demand-Side Management Programs

On August 10, 2010, the Company filed an application for approval of a number of strategic issues relating to its DSM plan, including long-term electric energy savings goals (Docket No. 10A-554EG). The Commission issued Decision No. C11-0442 ("DSM Strategic Issues Decision") on April 26, 2011 increasing the Company's electric energy savings goals the levels shown in Table 2.4-9.

Table 2.4-9 Energy Savings Goals Used in 2011 ERP

Year	2012	2013	2014	2015	2016	2017	2018
Energy Savings Goal (GWh)	330	356	384	411	411	411	411

The DSM Strategic Issues Decision also included escalating goals beyond 2015 but stated that "the savings goals for the later years of this period [2016-2020] are the most general in nature and the most subject to change with additional experience." For the years beyond 2015, the Company believes that the 411 GWh goal established for 2015 is a reasonable estimate of the maximum achievable savings from electric DSM in Colorado. To the extent that the Commission wants the Company to use DSM energy savings goals above these levels, the Reserve Margin would need to be adjusted to reflect the significant uncertainly in achieving higher goals.

The DSM Strategic Issues Decision did not include demand goals related to DSM. Instead the Commission directed the Company to propose demand reduction goals for 2012 and 2013 incorporating the combined effects of its energy efficiency initiatives, Savers Switch, the Interruptible Service Option Credit ("ISOC") and Third Party Demand Response programs, in its application for approval of its 2012-2013 DSM Plan. Docket No. 11A-631EG is currently pending to consider, among other issues, the appropriateness of the Company's proposed demand reduction goals for 2012 and 2013. For 2014 through 2020, in the DSM Strategic Issues Decision the Commission ordered the Company to file a formal Application seeking approval of demand reduction goals by April 26, 2012.

Among the issues addressed by the Commission in the DSM Strategic Issues Decision was whether the Company should be required to use competitive solicitation to acquire all DSM resources. The Commission refused to require the Company to acquire DSM resources through competitive solicitation but directed the Company "to make a more robust and transparent application of competitive bidding *as it implements an approved DSM plan."* (emphasis supplied). Accordingly, while the Company will continue to use competitive bidding to solicit vendors to assist it in implementing its approved DSM plans, the Company does not intend to solicit DSM resources as part of the competitive solicitation made as a result of the 2011 ERP.

To incorporate the impacts of future DSM, the Company has reduced its sales forecast assuming achievement of the energy savings goals through 2015 that the Commission established in the DSM Strategic Issues Decision. For 2016 through 2020 however, the Company assumed achievement of the 2015 goal of 411 GWh. For the demand forecast, the Company has assumed achievement of the 2012-2013 demand goals as filed in its 2012-2013 DSM Plan; the demand intensity (MW per GWh) estimated from the March 12, 2010 Colorado DSM Market Potential Assessment (Exhibit No. DLS-2 in Docket No. 10A-554EG) applied to the energy goals for years subsequent to 2013; and the demand impacts of the most recent forecast of load management achievements.

The Company believes that the expected impact of DSM on resource planning is best determined by the Commission in the context of those proceedings devoted exclusively to DSM rather than in the 2011 ERP. This is how the Commission has indicated that it intends to approach this issue. Indeed, in footnote 11 of the DSM Strategic Issues Decision, the Commission issued the following directive regarding the assumed demand savings to be used for resource planning purposes as a result of DSM:

> By this Order, we make no modification to the range of demand savings established in Docket No. 07A-420E for ERP modeling purposes. Specifically, demand savings through 2020 shall be in the range of 886 to 994 MW, not including Savers' Switch and ISOC. Decision No. C08-0560, at 22. However, we also recognize that

demand reduction goals could be established in a future docket before the completion of Phase 2 of the Company's next ERP proceeding.

For purposes of the 2011 ERP, the cumulative demand reduction from 2009 through 2020 associated with the Company's energy efficiency initiatives totals 866 MW. While the assumed demand reduction associated with the Company's DSM initiatives going forward is somewhat lower than was assumed in Docket No. 07A-420E, this result is largely due to an increase in energy efficiency standards affecting the Company's Business Cooling program. However, even though the Company's contribution to demand reduction as been reduced somewhat on account of the change in codes and standards affecting this program, the Company's sales forecast continues to reflect the reduction in peak demand associated with the change in standards. Thus, the total impact of energy efficiency initiatives taken by our customers whether directly attributable to the Company's energy efficiency initiatives or attributable to the increase codes adopted since the Commission issued its order in Docket No. 07A-420E have been captured in the sales forecast that forms the basis for the Company's resource need assessment.

Attachment 2.4-1 Owned Generation Unit Locations

Facility Name	Unit	Location
Arapahoe	3,4	Denver, near intersection of West Evans and Platte River Drive
Cherokee	1- 4	Commerce City, CO. Near intersection of Washington St. and 61st
Comanche	1 - 3	South end of Pueblo, CO, east of I-25
Craig	1,2	Near Craig, CO
Hayden	1,2	On the Yampa River, two miles east of Hayden, CO in Western CO
Pawnee	1,2	Four miles southwest of Brush, CO in Northeastern CO
Valmont	5,6	East Boulder, CO off of Arapahoe Road
Zuni	2	Downtown Denver, CO, next to Mile High Stadium
Alamosa	1,2	One mile South of the city of Alamosa, CO, in the San Luis Valley
Blue Spruce	1,2	N Powhaton Rd, Aurora, CO
Fruita	1	Ten miles northwest of Grand Junction, CO, near the Town of Fruita
Ft. Lupton	1,2	Two miles northeast of the town of Ft. Lupton, CO
Ft. St. Vrain	1-6	Three miles northwest of the town of Platteville, CO,
Rocky Mountain Energy Center	1,2,3	County Road 51, Keenesburg, CO
Ames	1	South Fork of the San Miguel River, approximately ten miles south-southwest of Telluride, CO
Cabin Creek	1,2	South of Georgetown, CO
Georgetown	1, 2	On South Clear Creek in the town of Georgetown, CO
Salida	1,2	On the South Arkansas River, approx. six miles east of Poncha Springs, CO
Shoshone	1,2	On the Colorado River in Glenwood Canyon, six miles east of the town of Glenwood Springs, CO
Tacoma	1,2	On the Animas River, approximately eighteen miles north of Durango, CO
Cherokee Diesel	1, 2	Commerce City, CO, near intersection of Washington St. and 61st St.
Ponnequin Wind	8-44	Four miles east of I-25 and 2 miles west of US 85, immediately adjacent to and south of the Colorado-Wyoming State line.

Attachment 2.4-2 Owned Generation Unit Descriptions

Facility Name	Unit	Gross Maximum Capacity (MW)	Net Dependable Capacity Summer (MW)	Net Dependable Capacity Winter (MW)	Fuel Type
Arapahoe	3	48	44	44	Coal
Arapahoe	4	118	109	109	Coal
Cherokee	1	117	107	107	Coal
Cherokee	2	114	106	106	Coal
Cherokee	3	165	152	152	Coal
Cherokee	4	383	352	352	Coal
Comanche	1	360	325	325	Coal
Comanche	2	365	335	335	Coal
Comanche	3	573	511	522	Coal
Craig	1	43	42	42	Coal
Craig	2	43	42	42	Coal
Hayden	1	153	139	139	Coal
Hayden	2	106	98	98	Coal
Pawnee	1	536	505	505	Coal
Valmont	5	196	184	184	Coal
Zuni	2	73	65	65	Gas, Oil
Alamosa	1	17	12.8	17	Gas
Alamosa	2	19	13.5	18.2	Gas
Blue Spruce	1	162	139	160	Gas
Blue Spruce	2	162	139	160	Gas
Fruita	1	20	15	20	Gas
Ft. Lupton	1	50	44.7	50	Gas
Ft. Lupton	2	50.2	44.7	50	Gas
Ft. St. Vrain	1	312	301	304	Gas
Ft. St. Vrain	2	138	123	134	Gas
Ft. St. Vrain	3	143	128	139	Gas
Ft. St. Vrain	4	143	128	139	Gas
Ft. St. Vrain	5	163	145	160	Gas
Ft. St. Vrain	6	162	144	159	Gas
RMEC	1	165	150	160	Gas
RMEC	2	165	150	160	Gas
RMEC	3	305	301	300	Gas
Valmont	6	53	43	53	Gas
Ames	1	3.8	3.8	3.8	Hydro
Cabin Creek	1	162	210	300	Hydro
Cabin Creek	2	162			Hydro
Georgetown	1	0.8	0.8	0.6	Hydro
Georgetown	2	0.8	0.8	0.6	Hydro
Salida	1	0.8	0.8	0.6	Hydro
Salida	2	0.6	0.8	0.6	Hydro
Shoshone	1	7.5	7.5	4.0	Hydro
Shoshone	2	7.5	7.5	4.0	Hydro
Tacoma	1	2.25	2.25	2.25	Hydro
Tacoma	2	2.25	2.25	2.25	Hydro
Ponnequin	All	26.7	3.2	3.2	Wind

Notes:

1. Share of Comanche Unit #3 is 66.66%.
2. Share of Craig Units are 9.72%.
3. Share of Hayden Unit #1 is 75.5%, Unit #2 is 37.5%.
4. The "Net Maximum" summer and winter capacities of Cabin Creek are based upon the normal duration of the seasonal peak load periods. The Cabin Creek upper reservoir can store approximately 1300 MW-hr of generation. The seasonal ratings of the units reflect the average generation that can be continuously maintained over the duration of the peak period for the respective season.
5. The MW output from the Georgetown Hydro Station is reduced when two units are operating simultaneously. This facility has one penstock for both units. When both units are in service, water resistance in the penstock is higher. Therefore, higher resistance results in lower water flow to each turbine and lower output by each turbine.
6. The MW output from Shoshone Hydro Station is lower during the winter months because of the very low stream water conditions in the Colorado River. Typically, during the winter Shoshone can maintain 8 MW for approximately 4 hours. If required, Shoshone can increase its output to 12 MW for short periods.
7. Capacity Credit for Wind resources is 12.5% of net dependable capacity.

Attachment 2.4-3 Owned Generation Availability

Unit Name	Unit #	Percent Availability Factor (1)	Heat Rate (2) Btu/kwh
Arapahoe	3	79.49	
Arapahoe	4	73.98	
Blue Spruce	1	95.48	
Blue Spruce	2	95.33	
Cherokee	1	79.09	
Cherokee	2	84.39	
Cherokee	3	85.80	
Cherokee	4	79.79	
Comanche	1	85.52	
Comanche	2	84.57	
Comanche (4)	3	89.27	
Hayden	1	89.64	
Hayden	2	94.60	
Craig	1	93.09	
Craig	2	92.57	
Pawnee	1	84.03	
Rocky Mt Energy Ctr	CC 1-3	92.62	
Valmont	5	81.56	
Zuni	2	93.55	
Alamosa	1	93.75	
Alamosa	2	91.50	
Fruita	1	90.53	
Ft. Lupton	1	93.39	
Ft. Lupton	2	88.64	
Fort St. Vrain	CC 1-4	88.36	
Fort St. Vrain (5)	5	90.73	
Fort St. Vrain (5)	6	90.22	
Valmont	6	88.36	
Ames	1	90.44	
Georgetown	1	69.94	
Georgetown	2	97.95	
Palisade	1	77.42	
Palisade	2	78.92	
Salida	1	67.97	
Salida	2	75.32	
Shoshone	1	56.79	
Shoshone	2	47.45	
Tacoma	1	80.79	
Tacoma	2	89.62	
Cabin Creek	A	69.21	
Cabin Creek	B	60.36	
Cherokee Diesel (3)	1	98.00	
Cherokee Diesel (3)	2	98.00	
Ponnequin (3)	8-14	99.99	
Ponnequin (3)	15-21	99.99	
Ponnequin (3)	22-29	99.99	
Ponnequin (3)	30-38	99.99	
Ponnequin (3)	39-44	99.99	

Notes:

(1) Based on historical data from years 2006-2010.
(2) Unit heat rates are considered confidential information.
(3) Estimation of availability factor.
(4) Based on historical data from July 2009 to Dec 2010.
(5) Based on historical data from Apr 2009 to Dec 2010.

Attachment 2.4-4 Estimated Remaining Useful Life

Plant/Unit	Estimated Retirement Year
STEAM PRODUCTION	
Arapahoe Unit 3 (1)	2013
Arapahoe Unit 4 Coal	2013
Arapahoe Unit 4 Gas	2023
Cherokee Unit 1	2012
Cherokee Unit 2	2011
Cherokee Unit 2 Condenser	2027
Cherokee Unit 3	2016
Cherokee Unit 4 Coal	2017
Cherokee Unit 4 Gas	2028
Comanche Unit 1	2033
Comanche Unit 2	2035
Comanche Unit 3	2070
Craig Unit 1	2040
Craig Unit 2	2039
Hayden Unit 1	2030
Hayden Unit 2	2036
Pawnee Unit 1	2041
Valmont Unit 5	2017
Zuni Unit 2	2014
HYDRAULIC PRODUCTION	
Ames	2050
Cabin Creek	2044
Georgetown	2036
Salida	2027
Shoshone	2058
Tacoma	2050
OTHER PRODUCTION	
Fruita CT	2019
Ft. Lupton CT	2020
Alamosa	2019
Blue Spruce CT 1	2050
Blue Spruce CT 2	2050
Cherokee CC 5, 6, 7	2055
Fort St. Vrain ST 1	2041
Fort St. Vrain GT 2	2041
Fort St. Vrain GT 3	2041
Fort St. Vrain GT 4	2041
Fort St. Vrain GT 5	2049
Fort St. Vrain GT 6	2049
Rocky Mountain 1,2,3 CT 2x1	2050
Valmont CT	2019
Ponnequin Wind Farm	2024

(1) Arapahoe 3 was approved for conversion to a synchronous condenser in the CACJA. Public Service does not believe that the conversion is needed and will perform studies and make a report to the Commission at the end of 2012.

Attachment 2.4-5 Capacity Factor Estimates

		2012	2013	2014	2015	2016	2017	2018
Coal Fired								
Arapahoe	3	56.0%	58.8%					
Arapahoe	4	62.7%	61.2%	1.0%	0.5%	0.4%	0.5%	0.3%
Cherokee	1	42.7%						
Cherokee	2							
Cherokee	3	73.3%	76.9%	80.8%	71.5%			
Cherokee	4	72.5%	65.1%	67.6%	73.5%	74.8%	70.5%	4.4%
Comanche	1	81.6%	79.4%	67.0%	82.7%	82.8%	77.4%	85.1%
Comanche	2	78.0%	69.8%	82.3%	82.5%	69.0%	84.7%	86.2%
Comanche	3	85.1%	82.9%	84.6%	77.5%	85.2%	85.8%	79.7%
Craig	1	85.6%	83.1%	86.1%	84.3%	85.2%	87.0%	89.0%
Craig	2	84.8%	82.6%	85.5%	83.1%	84.4%	86.7%	88.9%
Hayden	1	73.0%	86.3%	88.5%	82.5%	87.1%	88.1%	75.6%
Hayden	2	92.8%	91.2%	85.2%	94.0%	93.9%	85.1%	93.6%
Pawnee	1	81.4%	81.8%	67.0%	81.1%	81.9%	76.7%	84.3%
Valmont	5	66.9%	74.8%	78.6%	73.2%	79.2%	80.6%	
Gas Combined Cycle/Steam								
Fort Saint Vrain	CC	20.8%	25.5%	37.5%	36.6%	26.4%	34.3%	41.4%
Rocky Mountain	CC	30.3%	23.3%	24.6%	20.9%	23.4%	24.1%	42.8%
Cherokee 2x1	CC					61.5%	66.9%	67.1%
Zuni	2	0.1%	0.2%	0.2%				
Gas Combustion Turbine								
Valmont	6	0.1%	0.2%	0.2%	0.2%	0.2%	0.3%	0.2%
Blue Spruce	1	0.3%	0.6%	0.6%	0.7%	0.5%	1.0%	2.4%
Blue Spruce	2	0.5%	0.9%	1.2%	1.3%	0.8%	1.4%	3.4%
Alamosa	1	0.0%	0.1%	0.1%	0.1%	0.2%	0.3%	0.2%
Alamosa	2	0.1%	0.2%	0.2%	0.2%	0.2%	0.3%	0.2%
Fruita	1	0.0%	0.1%	0.1%	0.1%	0.2%	0.3%	0.2%
Fort Lupton	1	0.1%	0.3%	0.3%	0.3%	0.3%	0.4%	0.3%
Fort Lupton	2	0.1%	0.2%	0.2%	0.2%	0.2%	0.4%	0.2%
Fort Saint Vrain	5	4.7%	6.1%	7.4%	7.2%	5.1%	6.6%	6.5%
Fort Saint Vrain	6	3.3%	4.5%	5.0%	5.2%	3.8%	4.8%	7.6%
Diesel								
Cherokee Diesel	1	0%	0%	0%	0%	0%	0%	0%
Cherokee Diesel	2	0%	0%	0%	0%	0%	0%	0%
Hydro								
Ames		40.9%	31.7%	34.9%	40.9%	31.7%	31.7%	34.9%
Georgetown		35.1%	25.6%	35.1%	35.1%	30.1%	30.1%	35.1%
Salida		34.9%	34.9%	36.6%	34.9%	34.9%	34.9%	41.8%
Shoshone		63.4%	67.4%	67.4%	63.4%	61.8%	61.8%	67.4%
Tacoma		22.8%	15.7%	14.3%	17.1%	15.7%	14.3%	14.3%
Pumped Storage								
Cabin Creek	A	18.3%	18.2%	17.8%	18.2%	17.8%	17.7%	17.7%
Cabin Creek	B	18.3%	18.2%	17.8%	18.2%	17.8%	17.7%	17.7%
Wind								
Ponnequin	8-22	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%
Ponnequin	23-29	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%
Ponnequin	30-38	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%
Ponnequin	39-44	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%

Attachment 2.4-6 PPA Duration and Modification Terms

Purchase Power Contract	Contract Duration (Termination Year)	Contract Provisions that allow for modification of the amount of capacity & energy purchased
Alamosa Solar	20 years from COD	During 2008 and each Commercial Operation Year thereafter (1) two hundred twenty four dollars ($224 00) per MWh, up to one hundred fifteen percent (115%) of the Committed Solar Energy for that Commercial Operation Year, plus (2) fifty six dollars ($56 00) per MWh in excess of one hundred fifteen percent (115%) of the Committed Solar Energy for that Commercial Operation Year.
On Site Solar	Various	None
Basin 1	2016	On or before end of each Season, Basin shall notify Public Service of amount of Excess Cap & energy above Contract Amt. Within 30 days Public Service shall, at its sole discretion, determine amount, if any, of add'l it will agree to purchase.
Basin 2	2016	On or before end of each Season, Basin shall notify Public Service of amount of Excess Cap & energy above Contract Amt. Within 30 days Public Service shall, at its sole discretion, determine amount, if any, of add'l it will agree to purchase.
Brush 1 & 3	2017	None
Brush 2	2009	None
Brush 4D	2022	None
Cedar Creek Wind	2027	For all Renewable Energy delivered by Seller to Public Service at the Point of Delivery in a Commercial Operation Year which is in excess of one hundred twenty percent (120%) of the Committed Renewable Energy, Public Service shall pay Seller at an energy payment rate equal to fifty percent (50%) of the Renewable Energy Payment Rate.
Colorado Green	2013	Contract Energy shall include Excess Energy, although Excess Energy shall be purchased by Public Service at the Excess Energy Payment Rate as set forth in Section 8 .3 .
ManChief	2012 (PH 1) 2022 (PH 2)	Seller shall have the right to offer to Public Service Excess Capacity.
Fountain Valley	2012	None

Attachment 2.4-6 Continued

Purchase Power Contract	Contract Duration (Termination Year)	Contract Provisions that allow for modification of the amount of capacity & energy purchased
PacifiCorp (w/reserves)	2011	Under the PacifiCorp LTPSA, Public Service already exercised its right to reduce its obligation to purchase capacity and energy starting in 2008 (Section 3.2). However, Public Service's election has been disputed by PacifiCorp. The Exchange agreement temporarily resolved the matter for at least a few years. Depending on the ultimate outcome of this dispute, Public Service does have an additional option to reduce the capacity, this time starting 2018 (Section 3.2). Under the PacifiCorp Exchange agreement, PacifiCorp has the right, on an annual basis starting in 2012, to reduce the amount of capacity and energy made available to Public Service (Section 4.7).
Peetz Table/Logan Wind	25 years from COD	Public Service shall pay Seller for Renewable Energy delivered to Public Service by Seller to the Point of Delivery in a Commercial Operation Year up to one hundred fifteen percent (115%) of the Committed Renewable Energy at the Renewable Energy Payment Rate. For all Renewable Energy delivered by Seller to Public Service at the Point of Delivery in a Commercial Operation Year which is in excess of one hundred fifteen percent (115%) of the Committed Renewable Energy, Public Service shall pay Seller at an energy payment rate equal to fifty percent (50%) of the Renewable Energy Payment Rate.
Plains End	2012 (Ph 1;)2028 (Ph 2)	None
Ridge Crest Wind	2016	During the Term of this WESA, in the event the Facility, as originally described in Exhibit C, is able to produce energy in excess of seventy-seven gigawatt hours (77 GWh) in a Commercial Operation Year ("Excess Energy"), Public Service shall purchase such Excess Energy, at the rate specified in Section 8 .4 subsequent to the production of more than seventy-seven gigawatt hours (77 GWh) in a Commercial Operation Year.
Spindle Hill CT	2027	None
Small QFs (21 contracts)	Various	Has provisions requiring Seller to offer any Excess Capacity and Excess Energy to Public Service prior to offering it to third parties (Section 7.3(B)).

Attachment 2.4-6 Continued

Purchase Power Contract	Contract Duration (Termination Year)	Contract Provisions that allow for modification of the amount of capacity & energy purchased
Southwest Generation Arapahoe	2012	Section 7.4(C) requires Seller to offer any Excess Capacity and Excess Energy to Public Service prior to offering it to third parties.
Southwest Generation Valmont	2012	If the Expanded Facility is able to produce Excess Capacity in excess of one MW, seller may elect to sell to Public Service and Public Service shall be required to purchase, not in excess of 10 MW
Spring Canyon Energy	2026	For all Renewable Energy delivered by Seller to Public Service at the Point of Delivery in a Commercial Operation Year which is in excess of one hundred fifteen percent (115%) of the Committed Renewable Energy, Public Service shall pay Seller at an energy payment rate equal to fifty percent (50%) of the Renewable Energy Payment Rate.
Thermo Cogen	2019	Not required to purchase excess capacity
Thermo Greeley (Monfort)	2011	Public Service Company shall not be obligated to purchase Capacity Output in excess of 32,000 KW
Thermo Power (UNC-Greeley)	2013	Public Service agrees to buy and Thermo Power may sell, add'l capacity up to but not exceeding 3,854 KW during summer & add'l capacity up to but not exceeding 1,349 KW during winter seasons.
Tri-State Generation and Transmission (“TSG&T” or “Tri-State”) 2	2017	Before end of each season, Tri-State shall notify Public Service of amount of excess capacity, if any. Within 30 days after notice Public Service will determine amount of excess capacity & energy it will agree to purchase.
Tri-State 3	2016	None
Tri-State 5	2011	None
Tri-State Brighton	2016	Public Service required to purchase up to 10 MW of excess capacity
Tri-State Limon	2016	Must offer to sell excess capacity to Public Service before selling to a third party
Twin Buttes	2027	For all Renewable Energy delivered by Seller to Public Service at the Point of Delivery m a Commercial Operation Year which is m excess of one hundred fifteen percent (115%) of the Committed Renewable Energy, Public Service shall pay Seller at an energy payment rate equal to fifty percent (50%) of the Renewable Energy Payment Rate
WM Landfill Gas	TBD	None

Attachment 2.4-7 2010 Water Consumption

Generating Station	Annual Net Generation (MWh)	Annual Consumptive Use (gallons)	Water Intensity (gallons/MWh)
Public Service - Owned			
Arapahoe	608,811	360,445,625	592
Zuni	3,739	5,008,330	1339
Cherokee	3,671,855	1,976,467,945	538
Comanche	9,279,180	2,840,037,399	306
Pawnee	3,378,800	1,516,418,733	449
Hayden	3,817,906	1,216,314,000	319
FSV	3,347,997	597,832,892	179
Valmont	1,090,643	1,206,952,104	1107
Rocky Mountain Energy Center	2,889,657	728,016,304	252
Hydro-power plants	66,652	51,240,070	769
Alamosa*	3,631.8	-	0
Blue Spruce Energy Center*	379,789.0	-	0
Ft. Lupton*	3,181.1	-	0
Fruita*	578.8	-	0
Total - Owned Facilities	***28,542,421***	***10,498,733,402***	***368***

* Internal combustion engines and existing CT Turbine facilities require no water for generation using gas.

Attachment 2.4-7 Continued

Generating Station	Annual Net Generation (MWh)	Annual Consumptive Use (gallons)	Water Intensity (gallons/MWh)
IPP - Gas			
Southwest Generation (Arapahoe)	123,153	58,488,099	475
Brush 1 & 3	14,281	6,036,000	423
Brush 4D	60,167	38,946,000	647
Thermo Cogen	437,912	249,168,000	569
Thermo Power & Electric (UNC Greeley)	123,153	32,685,000	265
Southwest Generation (Valmont)*	12,196	-	0
Fountain Valley Power, LLC*	402,683	-	0
Manchief Power Company LLC*	187,075	-	0
Plains End II, LLC*	137,681	-	0
Plains End LLC*	24,988	-	0
Spindle Hill Energy LLC*	568,883	-	0
WM Renewable Energy*	19,593	-	0
Tri-State G & T Assoc - Brighton*	N/G	-	0
Tri-State G & T Assoc - Limon*	N/G	-	0
Total - IPP Gas	***2,111,765***	***385,323,099***	***182***
IPP - Wind			
Cedar Creek Wind Energy, LLC	851,207	-	0
Cedar Creek II, LLC	N/G	-	0
Cedar Point Wind, LLC	N/G	-	0
Colorado Green Holdings LLC	571,650	-	0
Foote Creek III LLC	71,695	-	0
Limon Wind, LLC	N/G	-	0
Logan Wind Energy LLC	650,000	-	0
NREL's NWTC, ALSTOM Power, Inc	N/G	-	0
NREL/DOE (NWTC)	N/A	-	0
Northern Colorado Wind Energy I	400,000	-	0
Northern Colorado Wind Energy II	5,635	-	0
Peetz Table Wind Energy, LLC	650,000	-	0
Ponnequin I	8,716	-	0
Ridge Crest Wind Partners LLC	92,973	-	0
Siemens Energy, Inc	1,495	-	0
Spring Canyon Energy LLC	202,348	-	0
Twin Buttes Wind	269,814	-	0
Total - IPP Wind	***1,808,819***	-	***0***

* Internal combustion engines and existing CT Turbine facilities require no water for generation using gas.

N/A - Data not available

N/G - No generation in 2010

N/S - System purchases in 2010

Attachment 2.4-7 Continued

Generating Station	Annual Net Generation (MWh)	Annual Consumptive Use (gallons)	Water Intensity (gallons/MWh)
IPP - Hydro		-	0
Bridal Veil	1,860	-	0
Boulder - Silverlake	13,447	-	0
Boulder - Betasso	9,946	-	0
Boulder - Kohler	689	-	0
Boulder - Lakewood	9,946	-	0
Boulder - Maxwell	566	-	0
Boulder - Orodell	558	-	0
Boulder - Sunshine	3,561	-	0
Denver Water - Dillon Dam	N/A	-	0
Denver Water - Foothills Water Treatment	N/A	-	0
Denver Water - Hillcrest Hydroelectric	N/A	-	0
Denver Water - Roberts Tunnel	N/A	-	0
Denver Water - Strontia Springs Dam	N/A	-	0
Denver Water - Gross Reservoir	N/A	-	0
Boulder - Boulder Canyon	8,566	-	0
Redlands Water & Power	8,097	-	0
Stagecoach	1,860	-	0
STS Hydro - Mt. Elbert	4,797	-	0
OrchardMesa/GrandValley/Palisade	N/G		0
Total - IPP Hydro	***63,892***	***-***	***0***
IPP - Solar			
SunE Alamosa	17,622	-	0
Boulder - 75th St.	N/A	-	0
Amonix SolarTAC 1, LLC	N/G	-	0
Cogentrix of Alamosa	N/G	-	0
Greater Sandhill 1, LLC	N/G	-	0
San Luis Solar, LLC	N/A	-	0
Total - IPP Solar	***17,622***	***-***	***0***

* Internal combustion engines and existing CT Turbine facilities require no water for generation using gas.
N/A - Data not available
N/G - No generation in 2010
N/S - System purchases in 2010

2.5 TRANSMISSION RESOURCES

Electric Transmission System

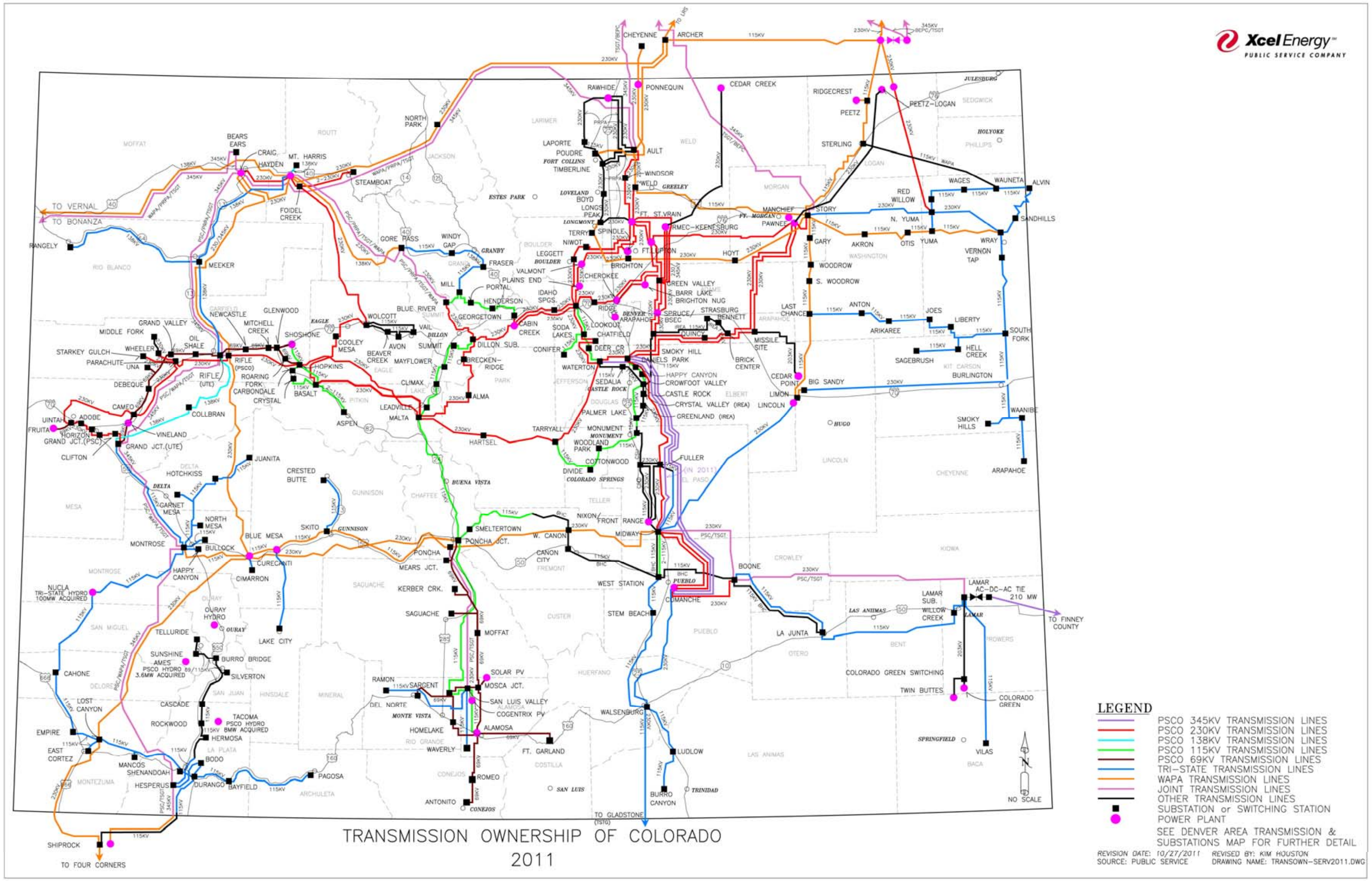
Public Service owns and maintains approximately 4,360 circuit-miles of transmission lines the majority of which are located inside Colorado. The transmission lines are rated 44 kV, 69 kV, 115 kV, 138 kV, 230 kV, and 345 kV. The Company also uses 223 transmission and distribution substations to deliver electric energy.

Colorado is on the eastern edge of the Western Electric Interconnection, which operates asynchronously from the Eastern Electric Interconnection. The Public Service–Southwestern Public Service Company Tieline and 210 MW High Voltage Direct Current ("HVDC") back-to-back converter station, in-service since December 31, 2004, provides the first link in Colorado between the two Interconnections.

Public Service has ownership in the jointly owned western slope transmission facilities extending from the Craig/Hayden area in Northwestern Colorado south to the Four Corners area.

Please see Figure 2.5-1 for a map of the Colorado Transmission System including Public Service's transmission facilities.

Figure 2.5-1 Colorado Transmission Map



TOT Transmission Transfer Capability Limitations

Public Service shares ownership in four jointly-owned transmission corridors within the Colorado/WyomingUtah/New Mexico area. These jointly-owned transmission corridors are called “TOTs” which is an acronym for “total of transmission.” These TOTs are numbered 2A, 3, 5, and 7. The transfer capability across these TOTs is developed seasonally by coordination and agreement by the owners of the TOT facilities. The WECC Operating Transfer Capability Policy Committee reviews and approves the transfer capability.

Presently, Public Service transmission capacities on these transfer paths are committed to serve Public Service native load. Public Service posts available transmission capability (“ATC”) on the WestTrans OASIS node at http://www.oatioasis.com. Transmission tariffs, including transmission terms, conditions and pricing, are posted on the WestTrans OASIS node.

The bulk power transmission system within the Denver/Boulder metro area is a TOT-constrained region consisting primarily of a double-circuit 230 kV loop around the Denver metro region and a 345 kV and 230 kV path from Denver south to the Pueblo area. This outer belt loop feeds into the 230 kV and 115 kV load-serving networks at various points on the system. Public Service is adding a 345 kV transmission line from the Pawnee area into the Denver/Boulder metro area at Smoky Hill Substation.

Figure 2.5-2 illustrates the TOT locations. The power transferred across these TOT paths is continuously monitored to ensure that the path limits are not exceeded. All TOT’s have been rated by WECC and the transmission providers that jointly own the TOT’s. Public Service shows TOT1 in Figure 2.5-2 but does not further describe the TOT as Public Service does not own any portion of the TOT and has no rights on the TOT.

Figure 2.5-2 Colorado TOT Transmission Path Map

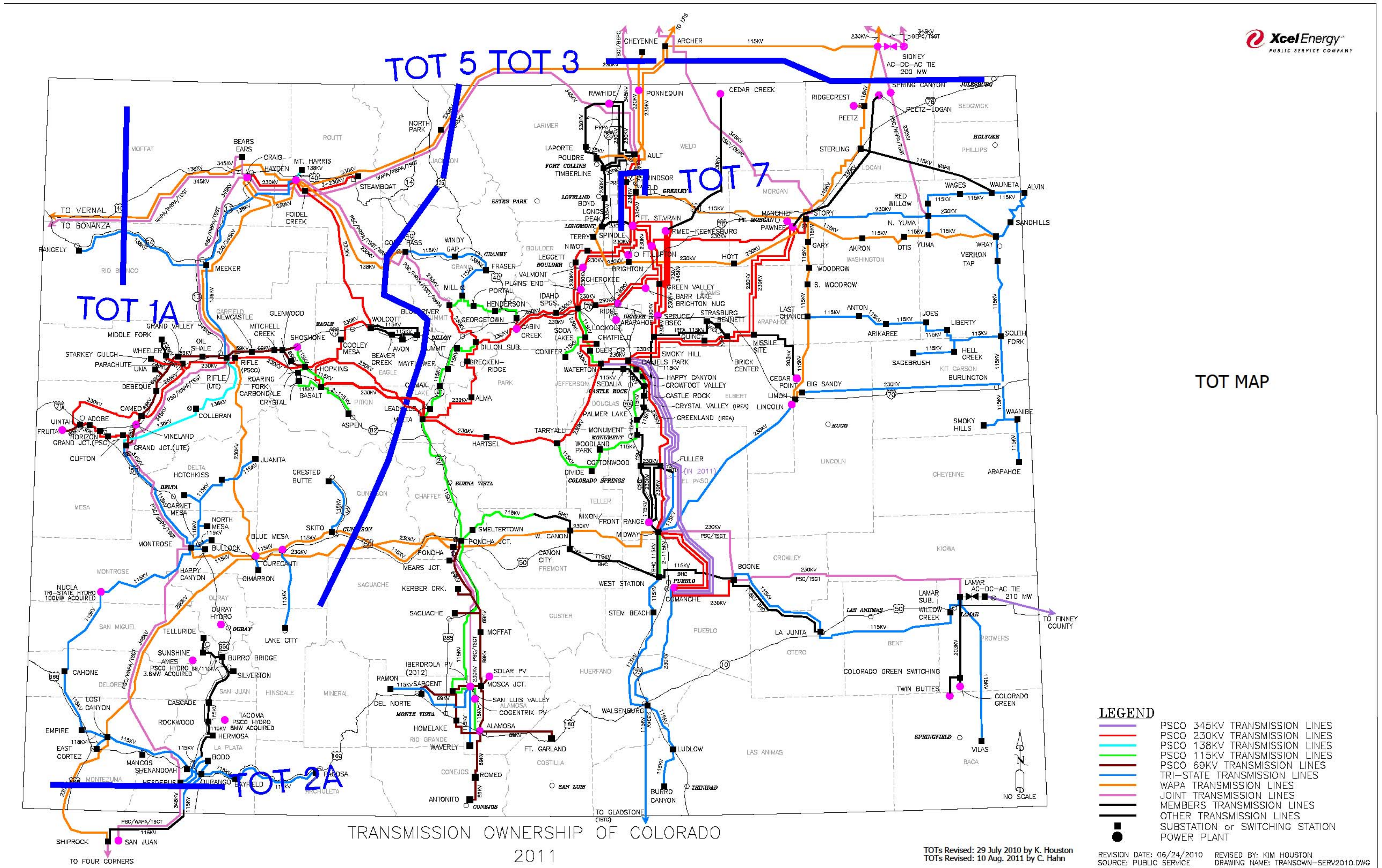


Table 2.5-1 shows Public Service's TOT capability on each path.

Table 2.5-1 TOT Transmission Transfer Capability Limitations (2011)

Path	Transmission Lines	Public Service Firm Path Transfer Capability (MW)		Public Service Capability Committed (MW)
TOT 2A	Waterflow-San Juan 345 kV Hesperus-Glade Tap 115 kV Lost Canyon-Shiprock 230 kV	135 north-south	200 south-north	135 north-south 200 south-north
TOT 3	Archer-Ault 230 kV LRS-Ault 345 kV LRS-Story 345 kV Cheyenne-Owl Creek 115 kV Sidney-Sterling 115 kV Sidney-Spring Canyon 230 kV Cheyenne-Ault 230 kV	56 north-south	56 south-north	56 north-south 0 south-north
TOT 5	North Park-Archer 230 kV Craig-Ault 345 kV Hayden-Gore Pass 230 kV Hayden-Gore Pass 138 kV Gunnison – Poncha 115 kV Curecanti-Poncha 230 kV Hopkins-Malta 230 kV Basalt-Malta 230 kV	480 west-east	480 east-west	480 west-east 480 east-west
TOT 7	Weld-Fort St. Vrain 230 kV Longs Peak -FSV 230 kV Ault-Fort St. Vrain 230 kV	516 north-south	516 south-north	516 north-south 2 south-north

<u>TOT 2A</u>

TOT 2A represents the transmission path that connects southwestern Colorado with New Mexico. This path is comprised of three transmission lines, has a north to south limit of 690 MW, and is based on single contingency of the Hesperus - San

Juan 345 kV line. The Path is jointly owned by WAPA, Tri-State, and Public Service. The south to north limit is not defined, but Public Service has ownership rights to 200 MW of transfer capability in the south to north direction on this path and a 135 MW share of the maximum north to south transfer capability of 690 MW. However, the limit is dynamic and monitored continuously. The limit is also highly dependent on local southwest Colorado loads and drops significantly as the loads increase and when southwest Colorado generation is off-line.

<u>TOT 3</u>

TOT 3 is essentially the transmission path that connects Wyoming and Nebraska with eastern Colorado. This path is comprised of seven transmission lines and presently has a maximum north to south transfer limit of 1,680 MW that is adjusted seasonally to account for load and local generation variations.

WAPA, TSGT, Basin Electric Power Cooperative and Public Service jointly own the TOT 3 transmission lines. Public Service owns 56 MW of firm transfer capability on TOT 3 but presently depends on this TOT path for delivery of approximately 400 MW of purchased power from northwestern Colorado and southern Wyoming.

Operationally, TOT 3 is the most constraining transmission path used to import power into eastern Colorado. Once the TOT 3 capacity limit is reached, further schedules into eastern Colorado over TOT 5 result in the overloading of TOT 3.

<u>TOT 5</u>

TOT 5 represents the transmission path that connects western Colorado to eastern Colorado. The TOT 5 path is comprised of eight transmission elements and presently has a west to east operating transfer limit of 1,675 MW. The west to east rating of the path is defined through established operating practices. WAPA, Tri-State, PRPA, and Public Service jointly own the TOT 5 transmission lines. Public Service owns 480 MW of firm transfer capability on TOT 5 (west-east) and, since the path is not formally rated in that direction, the same 480 MW east to west. It should be noted that rating the path from east to west is currently under study.

Public Service's 480 MW firm transfer capability in the west to east direction on TOT 5 is fully committed to transmitting capacity and associated energy from the Company's purchased power resources and from Company-owned resources located in western Colorado. PSCo has committed the east to west direction as backup for western Colorado loads and for counter-scheduling needs.

<u>TOT 7</u>

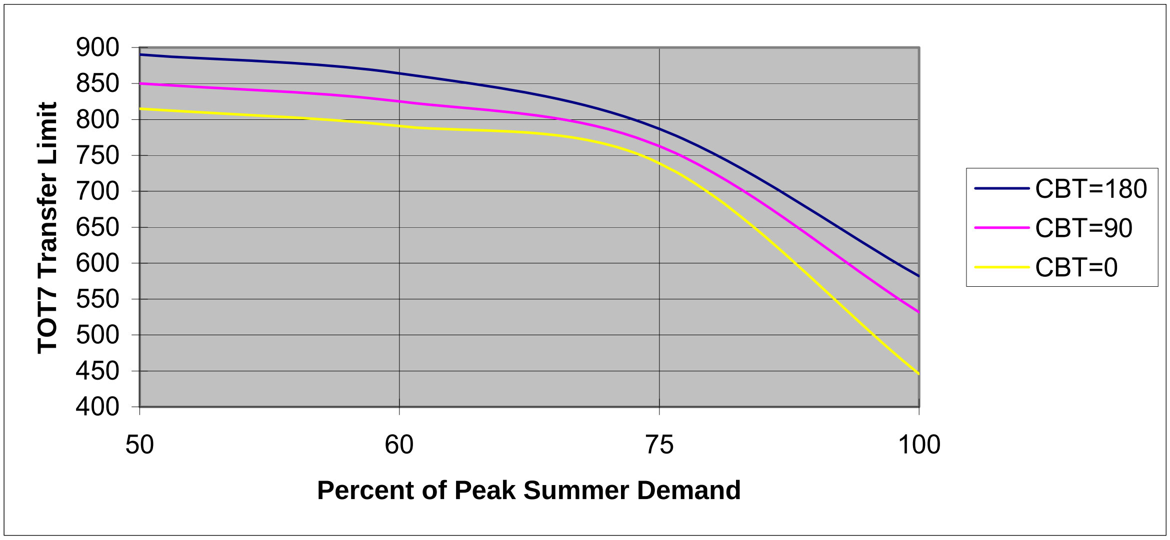
TOT 7 is south of the TOT 3 path and consists of three transmission lines that transfer power to the north Denver-metro area. The TOT 7 path has a north to south transfer limit of 890 MW.

Public Service and PRPA jointly own TOT 7. Public Service owns 516 MW of firm transfer capability on TOT 7. Since TOT 7 is located east of TOT 5 and south of

TOT 3, TOT 7 use generally requires coordinated use of both the TOT 3 and TOT 5 paths.

TOT 7 is dynamically limited as shown in Figure 2.5-3

Figure 2.5-3 TOT 7 Real Time Transfer Limit



The local area has experienced a steady increase in demand over the years. As a result, the real-time rating of the TOT 7 transfer path has decreased. Figure 2.5-3 illustrates constraint over varying levels of energy production by the Colorado Big Thompson Project ("CBT" in Figure 2.5-3).

SB07-100 New Transmission Additions

SB 07-100 requires rate-regulated electric utilities such as Public Service to, on or before October 31 of each odd-numbered year, do the following:

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

Public Service filed its first SB 07-100 Report on October 31, 2007. On November 24, 2008, Public Service filed a 2008 Informational Report and on October 30, 2009, the Company filed its most recent SB 07-100 Report. Public Service will file the SB

07-100 biennial report on October 31, 2011 and the report will be available on the Commission's e-filing system.

The ERZs were established in 2007 and revised by the 2008 Informational Report and the 2009 Report to the number and status described below.

ERZ 1: In Northeast Colorado, ERZ 1 includes all or parts of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld, and Larimer Counties. The geography of this ERZ is similar to the way it was described in the 2007 Report, but it has been redrawn to provide clarity so that major metropolitan areas (particularly the greater Denver area) are not included in any ERZ.

ERZ 2: ERZ 2 is in East Central Colorado, and includes all or parts of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson, Kiowa and Cheyenne Counties. The geography of this ERZ_is also similar to that described in the 2007 Report but has been redrawn to remove the greater Denver area as well as parts of Colorado Springs.

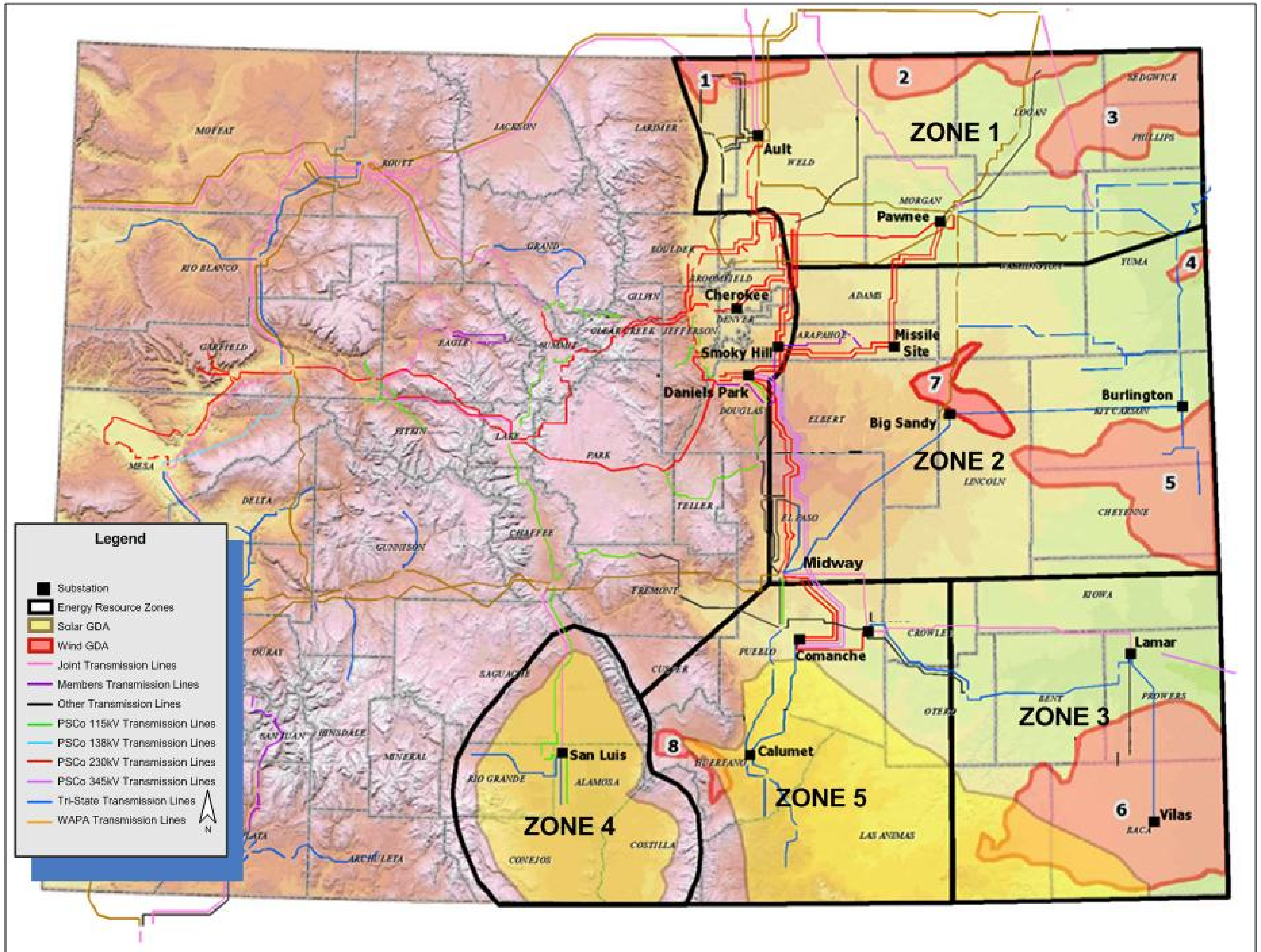
ERZ 3: ERZ 3 is in Southeast Colorado, and includes all of parts of Baca, Prowers, Kiowa, Crowley, Otero, Bent and Las Animas Counties. This ERZ is somewhat smaller than the ERZ 3 that was described in the 2007 Report; its western portion is now in ERZ 5, as is more fully described in the ERZ 5 description.

ERZ 4: ERZ 4 is in the San Luis Valley, and includes all or parts of Costilla, Conejos, Rio Grande, Alamosa, and Saguache Counties. This ERZ is somewhat smaller than the ERZ 4 created for the 2007 Report, as it now includes only the San Luis Valley region, and does not include any of Wind GDA 8 which is now located wholly within the new ERZ 5.

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

Figure 2.5-4 illustrates the five ERZs overlaid upon the wind and solar GDAs that were identified in the SB 07-091 Task Force Report.

Figure 2.5-4 Energy Resource Zones with GDAs



The SB07-100 projects that are likely to be on-line during the proposed Resource Acquisition Period are summarized below consistent with Commission Rule 3608 (b). The projects are described in more detail in the 2001 SB07-100 report filed by the Company on October 31, 2011.

Table 2.5-2 SB07-100 Projects Likely to be In-Service During the RAP

	Project	ERZ	CPCN Status	Currently Scheduled In-Service Date	Estimated Cost ($ Millions)	Injection Capability
1	**Missile Site 230 kV Switching Station**	2	Not Required[14]	In service November 2010	6.3	See Figure 2.5-5
2	**Midway-Waterton 345 kV Transmission Project**	3,4, 5	Granted: 7/16/2009	In service May 2011	42	Estimated 200 MW
3	**Pawnee-Smoky Hill 345 kV Transmission Project**	1	Granted: 2/26/2009	January 2013	155	See Figure 2.5-5
4	**Missile Site 345 kV Substation**	2	Granted: June 8, 2010	January 2013	15.5	See Figure 2.5-5

While the Company has a CPCN for the San Luis Valley–Calumet-Comanche Transmission 230/345 kV transmission line supporting ERZs 4 and 5, the Company does not expect that line to be in-service in its proposed RAP. It may be possible for some parts of the Lamar-Front Range line or the Pawnee-Daniels Park line to be in-service by 2018, but it is unlikely that a CPCN in either case would be issued before Phase 2 of the ERP is underway and therefore we do not consider it likely that those lines will be available during the RAP for this ERP. More details on these projects can be found in the 2011 SB07-100 report filed with the Commission on October 31, 2011.

Implemented SB07-100 Transmission Projects

1. Missile Site 230 kV Switching Station (ERZ 2)

    Description: The Missile Site 230 kV Substation Project consists of a new substation, near Deer Trail, Colorado that will connect to the existing Pawnee – Daniels Park 230 kV transmission line. The project will allow interconnection of approximately 250 MW of new generation in ERZ 2.

    Status: The Missile Site 230 kV switching substation was placed in service in November 2010. Public Service has also executed a PPA with 252 MW of wind from Cedar Point LLC in 2010. This wind project will be placed in service in 2011.

[14] Commission Rule dated 7/8/2008, Decision C08-0676

2. Midway – Waterton 345 kV Transmission Project (ERZs 3, 4, 5)

Description: The project consists of 82 miles of 345 kV transmission line from the Midway Substation, near Colorado Springs to the Waterton Substation, southwest of Denver. 72 miles would consist of operating an existing 230 kV line between Midway and Daniels Park at 345 kV, and the remaining 10 miles between Daniels Park and Waterton will consist of rebuilding an existing single-circuit line to a double-circuit line.

Status: The Midway – Waterton project remains a vital element of the Public Service transmission plan to accommodate additional generation resources in ERZs 3, 4, and 5. On April 20, 2009 the Company filed a petition for declaratory order requesting confirmation that the Commission's prior approval of a certificate of convenience and necessity ("CPCN") (September 2007- Decision 07-0750) for this project was still valid. The Commission issued its decision approving the project on July 16, 2009. (Decision No. C09-0775) Public Service placed the Midway – Waterton 345 kV Transmission Project in service in May 2011.

3. Pawnee – Smoky Hill 345 kV Transmission Project (ERZ 1)

Description: This project was filed in the 2007 Report and consists of developing approximately 95 miles of 345 kV transmission between the Pawnee Substation near Brush, Colorado, and the Smoky Hill Substation, east of Denver. The project will allow for approximately 500 MW of additional resources in ERZ 1, interconnected at or near the Pawnee and Missile-Site Substations. The planned Missile Site 345 kV substation would bisect the Pawnee – Smoky Hill 345 kV Project.

Status: An application for a CPCN was presented to the Commission for this project in October 2007. The CPCN for that project was approved by the Commission on February 26, 2009 (Decision No. C09-0048). Public Service anticipates that the project will be in service by January 2013.

4. Missile Site 345 kV Substation (ERZ 2)

Description: The Missile Site 345 kV Substation will expand the Missile Site 230 kV Switching Station to allow additional generator and transmission interconnections at the 345 kV voltage level. The Substation will bisect the Pawnee – Smoky Hill 345 kV Transmission Project. The Missile Site 345 kV Substation would allow additional generation from ERZ 2. In addition to connecting the Pawnee – Smoky Hill 345 kV line, the station would also allow for future 345 kV transmission connections. These may include connections to a Pawnee – Daniels Park 345 kV Project and connections to high voltage transmission to the south, such as to Big Sandy and Lamar.

Status: Public Service submitted a petition for a declaratory order on April 16, 2010 (Docket No: 10D-240E) that an application for a CPCN is not required to expand the Missile Site substation, or in the alternative, application for a CPCN for the expansion of the Missile Site substation. The Commission issued an order on June 8, 2010, Decision Number C10-0552. The Missile site 345 kV substation has been designed and it is being implemented with an in service date of January 2013. Missile Site 345 kV substation will consist of several 345 kV terminations including one for a 200 MW wind project in which a PPA of 200 MW was executed in May 2011.

Transmission Additions

Numerous transmission system facilities and upgrades to the Public Service system were completed in 2010 and 2011. Some projects are under construction. Many of these transmission system upgrades accommodate new generation facilities constructed as a result of the 2003 LCP, 2007 ERP and SB-100 processes. The new transmission line and substation projects in the approved 2011-2015 capital budget are as follows:

Transmission Facilities completed in 2010 and scheduled for completion in 2011

1) Comanche – Reader 115 kV line #2
2) Sandown - Leetsdale 115 kV constructed at 230 kV (Completed in 2010)
3) Midway - Waterton 345 kV (Completed May 2011)
4) Transmission associated with the Chambers substation (Completed December 2010)
5) Chambers (Completed December 2010)
6) Missile Site 230 kV switching station (Completed in 2010)
7) Plainview to Leyden 115 kV rebuild project (Completed in 2011)
8) College Lake 230/13.8 Distribution transformer (Completed in 2011)
9) Niwot-Gunbarrel 230 kV line #2 (Scheduled for completion in 2011)
10) Kelim 115-13.8 kV Substation (Completed in 2011)
11) Fairgrounds Substation for TSG&T (Completed in 2011)

Transmission projects submitted in the 2012-2016 capital budget (SB07-100 excluded)

1) Rifle to Parachute to Cameo 230 kV line
2) Malta 230/115 kV transformer
3) Poncha Junction 230/115 kV transformer
4) Blue Stone Valley Substation
5) Chamber 230/115 kV 2nd transformer
6) Godfrey Breaker station
7) Capacitor banks at Parachute and Cameo
8) Happy Canyon substation (IREA)
9) Weld 230 /115 kV 3rd autotransformer
10) Eldorado – Plainview 115 kV Upgrade
11) Una Cap Bank 69 kV
12) Monfort 115/44 kV Transformer

Please see Commission Docket No.11M-317E (Rule 3206 Filings) for greater detail.

Transmission Injection Capability

LGIA and Transmission Planning Studies

Public Service performs transmission studies for Large Generator Interconnection Agreement ("LGIA") requests. The LGIA requests are made to determine the feasibility, cost, time to construct and injection capability for the transmission system interconnection of an electric generating resource. The Company posts the results of these studies on its OASIS web-site.[15] The Company performs other transmission studies for purposes of transmission planning that determine like information.

The transmission system is interrelated and generation injection at one point on the system likely changes the injection capability at other points, e.g., generation injections at Pawnee would decrease the generation injection level at Missile Site and vice versa. The generation injection capability values provided below are approximations based on the stand-alone transmission studies performed for the LGIA requests. The generation injection capability values can change when Public Service performs additional specific resource and resource portfolio transmission studies whether for resource evaluation or a LGIA request. Table 2.5-3 lists the study determined injection capabilities.

Table 2.5-3 Injection Capabilities

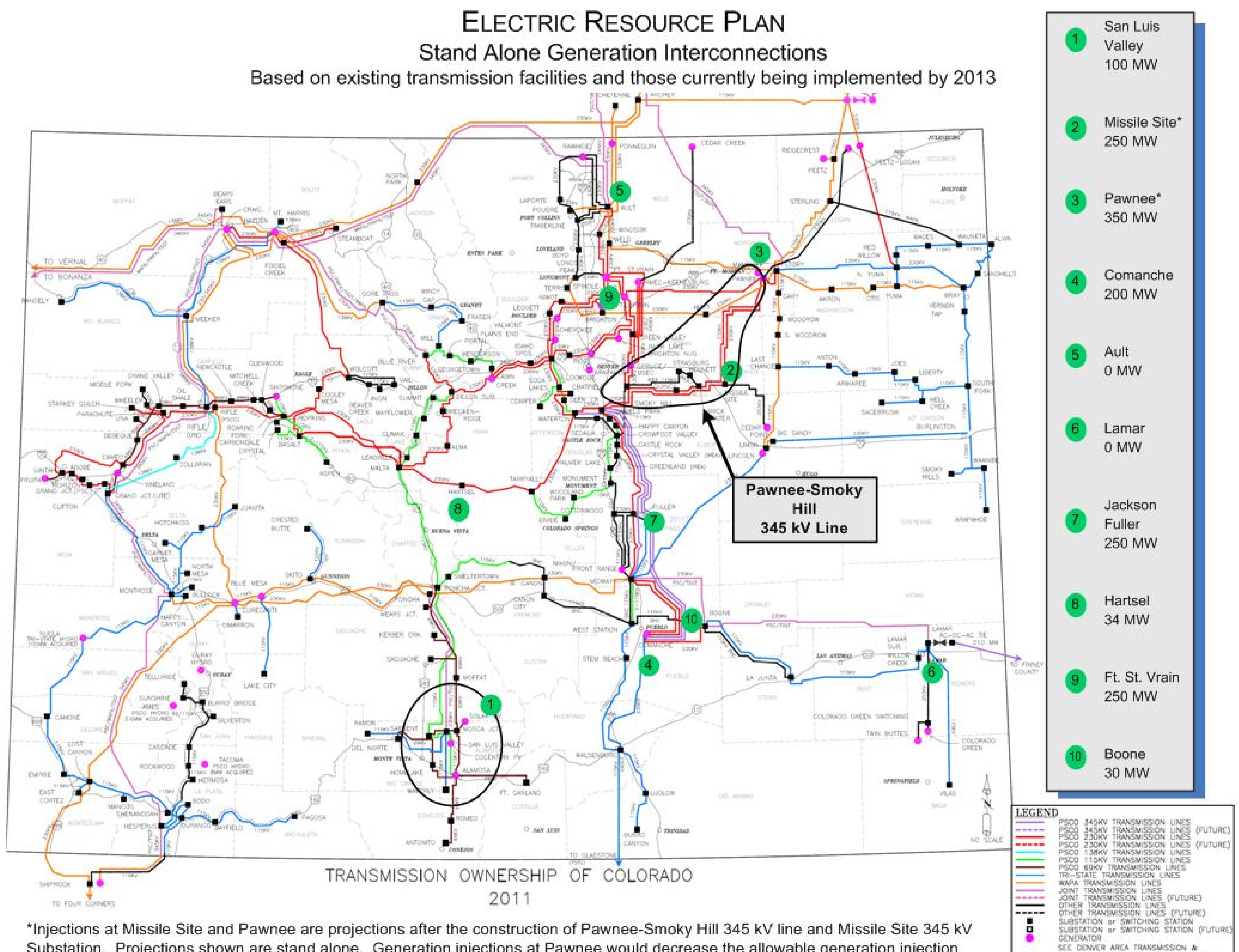
Location	LGIA Study	Injection Capability (MW)	Time to Construct
Comanche 345 kV	GI-2009-9	200	18 months
Jackson Fuller 230 kV	G1-2007-12	250	18 months
Missile Site 230/345 kV	Internal Planning	250	18 months
San Luis Valley area	GI -2008-26, GI-2009-8	100	18-24 months
Pawnee 230/345 kV	GI-2008-8	350	18 months
Lamar 230/345 kV	GI-2008-5	0	18 months
Ault 230 kV	GI-2008-30	0	18 months
Hartsel	G1-2008-23	34	18 months
Fort Saint Vrain	G1-2008-29	250	18 months
Boone	G1-2010-9	30	18 months

Note: Injections at Missile Site and Pawnee are projections after the construction of Pawnee-Smoky Hill 345 kV line and Missile Site 345 kV Substation. Projections shown are stand alone.

Figure 2.5-5 shows the injection points and values on a Public Service electric transmission system map.

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

Figure 2.5-5 Injection Values and Locations



*Injections at Missile Site and Pawnee are projections after the construction of Pawnee-Smoky Hill 345 kV line and Missile Site 345 kV Substation. Projections shown are stand alone. Generation injections at Pawnee would decrease the allowable generation injection level at Missile and vice versa.

Transmission Service Agreements

Public Service is party to a number of transmission service or "wheeling" agreements that are not specifically tied to PPAs. For example, Public Service is a network service customer of both the Platte River Power Authority ("PRPA") and the Western Area Power Administration ("WAPA"). Public Service uses this network service to provide electric energy to a number of Public Service retail load centers in the northern Front Range and northeastern Colorado. Public Service is also a customer of Tri-State for delivery of energy from Public Service's Ames Hydroelectric Generating Facility as well as delivery to a Public Service substation in Berthoud, Colorado.

The vast majority of Public Service's owned and purchased resources are located within the Public Service transmission system and have no specific wheeling agreement associated with them. Rather, in accordance with the requirements of the FERC, the merchant function of Public Service maintains a list of designated network resources that are delivered on behalf of the Public Service native load customers. This list is provided to the transmission function of Public Service and is posted on its OASIS.

The wheeling agreements Public Service uses to transfer power from its owned generation facilities and its PPAs to meet customer demand are listed below.

- The Public Service/Tri-State Contract for Interconnection and Transmission Service provides for up to 110 MW of exchanged transmission service that Public Service can use to import purchased resources from the north into the transmission-constrained Front Range of Colorado. Public Service currently uses this contract to 1) move a portion of the purchased power from the Tri-State 2 and 3 PPAs out of Wyoming's Laramie River Station to Colorado; 2) serve the City of Burlington across Tri-State's transmission system and 3) supplement Public Service's owned rights to import energy from the Lamar area. This contract terminates on October 1, 2014.
- Public Service has a long-term firm point to point service agreement with the transmission function of Public Service for the purchase of 188 MW of transmission service from the San Juan/Four Corners/Shiprock region to the Craig switchyard. This path is used to purchase capacity and energy at the Four Corners/San Juan marketplace. This contract terminates on January 31, 2015, but may be renewed in accordance with the open access tariff.
- Public Service is party to a Service Agreement for Network Integration Transmission Service with the Southwestern Public Service Company transmission function. The purpose of this agreement is to provide Public Service with access to Southwestern Public Service Company resources for delivery into Colorado across the Public Service – Southwestern Public Service Company Tieline (and the High Voltage Direct Current back-to-back Converter). Network Service is in an amount of 208 MW, and the contract terminates on February 29, 2012 but may be renewed in accordance with the open access tariff. Southwestern Public Service Company has a similar

arrangement for 210 MW of network service with the transmission function of Public Service. That contract also terminates on February 29, 2012 but has identical renewable conditions. Public Service expects that both of these arrangements will be extended beyond their existing termination dates.

- Public Service has also entered into short-term firm and non-firm transmission service agreements with over 30 transmission service providers, pursuant to the providers' Open Access Transmission Tariffs. These agreements are not transaction specific and have no specified MW quantity or term. Rather, these "umbrella" agreements allow (and are required in order for) Public Service to request and purchase short-term transmission services via the providers' OASIS Internet home pages. Such purchased transmission services are used to transmit short-term purchased resources to the Public Service system on an "as needed" basis.

In addition to Public Service's wheeling agreements, several of the Company's firm utility PPAs have transmission service provisions in the PPA contracts. These transmission service provisions are not specific wheeling agreements per se; however, they do affect Public Service's ability to import power into its system and ability to use PPA resources and are, therefore, summarized in Table 2.5-4.

Table 2.5-4 Wheeling Provided under Existing PPAs

Contract	Terms
Basin Electric Power Cooperative ("Basin") 1	Public Service pays Basin for wheeling contract-associated capacity and energy. Public Service has option to use an alternate firm transmission path to forego wheeling charge.
Basin 2	Same as Basin 1
Tri-State 2	Public Service pays Tri-State for wheeling contract-associated capacity and energy. Public Service has option to use the Public Service/Tri-State "Interconnection and Transmission Service Agreement" to wheel the Laramie River Station unit contingent portion of the contract capacity.
Tri-State 3	Same as Tri-State 2

Coordination Agreements

Public Service purchases short-term energy and capacity under two coordination agreements: the Western Systems Power Pool ("WSPP") Agreement and the Rocky Mountain Reserve Group ("RMRG") Agreement. The WSPP Agreement represents a marketing pool involving many supplier organizations throughout the United States. Many of Public Service's short-term firm and economy purchases are made under, and pursuant to the terms of, the WSPP Agreement. The RMRG Agreement is an operating reserve sharing agreement among several electric utilities operating in the Rocky Mountain Region. By pooling their operating reserves, these utilities are required to maintain less operating reserve capacity than if they operated independently. Under the RMRG Agreement, Public Service can call on and purchase operating reserves (spinning and non-spinning) and the energy associated with such reserves when they are activated in response to a system disturbance or system emergency. Public Service can also purchase emergency assistance under the RMRG Agreement.

Public Service also has entered into numerous service agreements with various utility suppliers and power marketers that allow Public Service to purchase short-term and economy energy at market rates, pursuant to the suppliers' or marketers' Sales Tariffs, on an "as needed" basis.

2.6 ELECTRIC ENERGY AND DEMAND FORECASTS

Introduction

Projections of future energy and peak demand are fundamental inputs into Public Service's resource need assessment. As required by ERP Rule 3606(b), Public Service prepared a base forecast and high and low forecast sensitivities.

Public Service projects base or median native load peak demand (retail and firm wholesale requirements customers) to grow at a compounded annual rate of 0.3% or an average of 19 MW per year through the RAP. This is larger than the 0.02% growth rate over the last five years. The loss of wholesale customers, high levels of DSM, and on-site solar during the historical period and during the Resource Acquisition Period (RAP) explains the lackluster growth rates. Public Service's low growth sensitivity for peak demand decreases at a compounded growth rate of -0.6% through 2018, and the high growth sensitivity for peak demand increases at a compounded growth rate of 1.1% per year over the same period of time.

Public Service projects base or median annual energy sales to increase at a compounded annual growth rate of 0.03% or an average of 11 GWh per year through the RAP. Public Service's low growth sensitivity for the forecast of annual energy sales decreases at a compounded annual growth rate of -0.8% through 2018, and the high growth sensitivity for the forecast of annual energy sales grows at a compounded rate of 0.8% per year.

Figures 2.6-1 and 2.6-2 show the base, high, and low forecasts of native load peak demand and energy sales graphically. Tables 2.6-1 and 2.6-2 show the data supporting the charts.

The base peak demand forecast assumes economic growth based on projections from IHS Global Insight, Inc., and median summer peak weather conditions.[16] Public Service estimates that there is a 70% chance that the actual peak demands will fall between the high and the low forecast scenarios.

[16] Median is synonymous with the 50th percentile, or it is higher than 50% of the estimates and lower than 50% of the estimates.

Figure 2.6-1 Native Load Peak Demand Forecasts

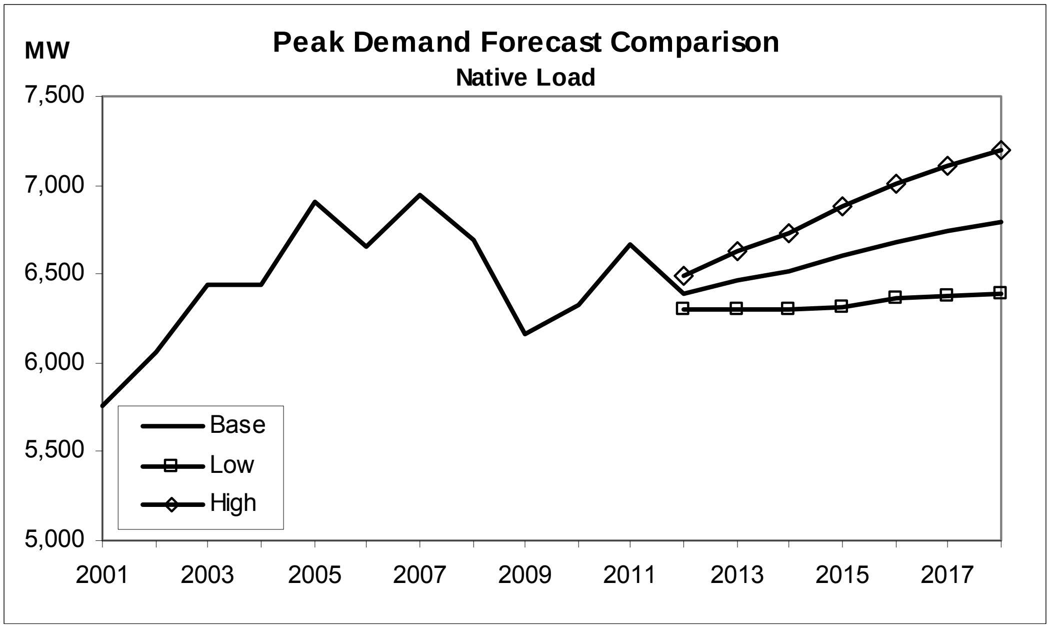
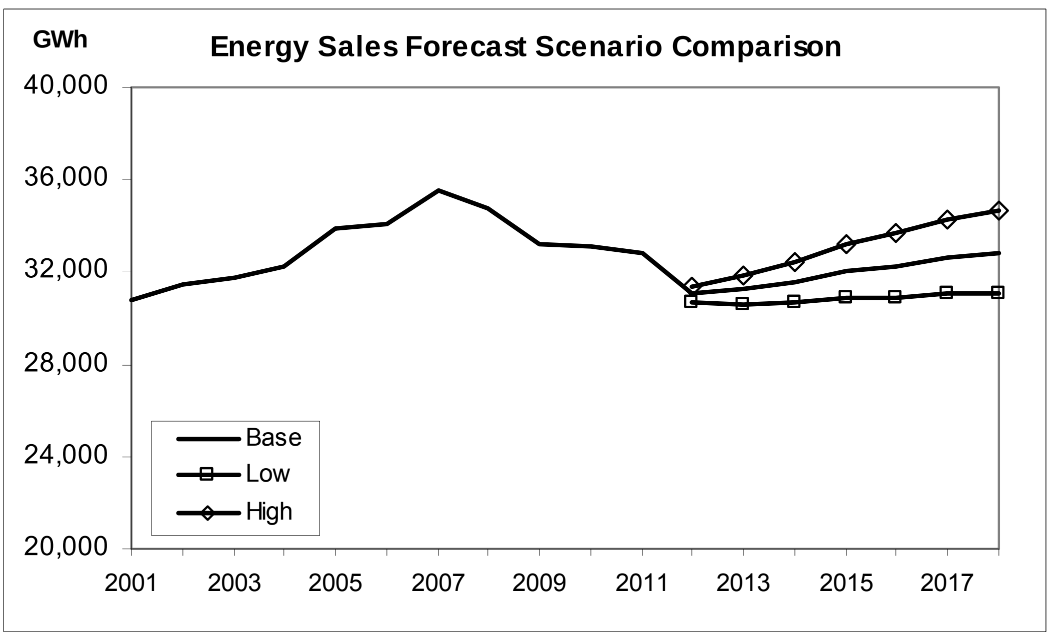


Figure 2.6-2 Native Load Energy Sales Forecasts



Peak Demand Discussion

Native load peak demand in Public Service's service territory has demonstrated anemic growth during the past five years, advancing just 8 MW. The expiration of wholesale contracts and the participation of wholesale customers in the Comanche 3 power plant have contributed to this weak load growth.[17] Since 2007, Public Service's firm wholesale load has decreased by 336 MW. The loss of wholesale load was offset by load growth within the retail sector, which has averaged gains of 0.8% or 44 MW annually during the past five years.

Colorado's economy was not immune to the prolonged downturn in the housing market and the financial sector crisis that started in 2008. The national recession impacted the Colorado economy, with declines in real personal income, real gross state product ("GSP"), non-farm employment, and home construction. In the five years ending in 2011, Colorado real GSP has averaged gains of 1.0% annually and real personal income advanced 1.1% annually. Large job losses in 2008 and 2009 resulted in a decline in non-farm employment since 2007, with decreases averaging -0.4% annually. Colorado population has increased 1.7% per year since 2007. During the same period, Public Service's residential sectors added 52,500 customers, an increase of 4.7% over the 2006 customer count.

The economic outlook for Public Service's service territory through the RAP in 2018 indicates that Colorado will experience stronger growth compared with the previous five years. Growth in Colorado real GSP and real personal income are expected to be 2.8% per year from 2011 to 2018. Nonfarm employment should advance by 1.7% annually over the same period. Population growth will continue at its recent historical pace of 1.8% annually. Public Service residential customers are expected to increase by 115,500 over the next 7 years with average gains of 1.4% per year through 2018.

Native load peak demand growth has been flat over the past 5 years with gains in the retail sector being offset by declines from wholesale load as contracts expired. Growth in Public Service's residential air conditioning load has stabilized over the last few years. The 2010 Residential Energy Use Survey conducted by Xcel Energy's Market Research Department indicates that 75% of Public Service's customers had some form of air condition/cooling system in 2010, which has remained flat compared with the 2008 survey (75%) and the 2006 survey (76%), but is up from the 2003 survey which reported that 63% of Public Service's customers had some form of air condition/cooling system.

[17] Public Services wholesale customers Intermountain Rural Electric Association and Holy Cross Energy reduced their wholesale load on Public Service's system by using a portion of the Comanche 3 coal-fired generation resource to serve their load.

We expect native load peak demand growth over the RAP, through 2018, to advance by 0.3% (19 MW) per year. Peak demand growth in 2012 will be negative with the expiration of the wholesale sales contract with Black Hills Colorado. During the period from 2013 to 2018, a period that is not influenced by the expiration of wholesale contracts, native load peak demand increases at a rate of 1.0%, or 68 MW per year.

Table 2.6-1 shows Public Service's native load summer peak demand forecasts along with ten years of history. It also shows annual growth and compounded growth to/from 2011. The bold line across the table delineates historical from projected information.

Table 2.6-1 Actual and Forecasted Summer Native Load Peak Demand[18]

	MW			**Annual Growth**			**Compound Growth to/from 2011**		
	Base	Low	High	Base	Low	High	Base	Low	High
2002	6,057			5.3%			3.2%		
2003	6,442			6.4%			1.1%		
2004	6,445			0.0%			1.1%		
2005	6,912			7.2%			-1.2%		
2006	6,656			-3.7%			0.0%		
2007	6,940			4.3%			-1.3%		
2008	6,692			-3.6%			-0.1%		
2009	6,160			-7.9%			2.7%		
2010	6,322			2.6%			1.8%		
2011	6,664			5.4%			0.0%		
2012	6,391	6,297	6,485	-4.1%	-5.5%	-2.7%	1.4%	-0.7%	-0.3%
2013	6,464	6,295	6,630	1.1%	0.0%	2.2%	1.0%	-0.7%	-0.1%
2014	6,521	6,302	6,734	0.9%	0.1%	1.6%	0.7%	-0.7%	0.1%
2015	6,599	6,315	6,882	1.2%	0.2%	2.2%	0.3%	-0.7%	0.4%
2016	6,682	6,362	7,012	1.3%	0.7%	1.9%	-0.1%	-0.6%	0.6%
2017	6,743	6,375	7,112	0.9%	0.2%	1.4%	-0.4%	-0.6%	0.8%
2018	6,797	6,386	7,197	0.8%	0.2%	1.2%	-0.7%	-0.5%	1.0%

<u>Annual Energy Discussion</u>

Table 2.6-2 shows Public Service's forecast for its total annual energy sales with ten years of history. It also shows annual growth and compounded growth to/from 2011. The bold line across the table delineates historical from projected information with the 2011 values reflecting actual sales through September.

[18] 1 megawatt (MW) = 1,000 kilowatts (kW)

The decrease in 2008 is caused by the termination of the firm wholesale contract with Cheyenne Light Fuel & Power Company. The decrease in 2010 and 2011 are due to the participation of Intermountain Rural Electric Association and Holy Cross Energy in the Comanche 3 project. The decrease in 2012 is attributable to the termination of the wholesale contract with Black Hills Colorado.

Table 2.6-2 Actual and Forecasted Annual Native Load Energy Sales[19]

	GWh			**Annual Growth**			**Compound Growth to/from 2006**		
	Base	Low	High	Base	Low	High	Base	Low	High
2002	31,432			2.0%			1.4%		
2003	31,710			0.9%			1.1%		
2004	32,275			1.8%			0.5%		
2005	33,921			5.1%			-1.1%		
2006	34,082			0.5%			-1.3%		
2007	35,544			4.3%			-2.7%		
2008	34,764			-2.2%			-1.9%		
2009	33,213			-4.5%			-0.4%		
2010	33,146			-0.2%			-0.4%		
2011	32,774			-1.1%			0.0%		
2012	31,046	30,706	31,387	-5.3%	-6.3%	-4.2%	1.8%	-0.8%	-0.5%
2013	31,248	30,606	31,865	0.7%	-0.3%	1.5%	1.6%	-0.9%	-0.4%
2014	31,550	30,650	32,460	1.0%	0.1%	1.9%	1.3%	-0.8%	-0.1%
2015	32,052	30,881	33,210	1.6%	0.8%	2.3%	0.7%	-0.7%	0.2%
2016	32,270	30,892	33,654	0.7%	0.0%	1.3%	0.5%	-0.7%	0.3%
2017	32,635	31,039	34,225	1.1%	0.5%	1.7%	0.1%	-0.7%	0.5%
2018	32,849	31,067	34,616	0.7%	0.1%	1.1%	-0.1%	-0.7%	0.7%

Due to the declines in wholesale sales, native load energy sales have decreased an average of -0.8% (-262 GWh) per year from 2007 to 2011. During the RAP ending in 2018, growth in native load energy sales will remain flat, advancing just 0.03% per year. The forecasted growth rate from 2013 to 2018, which is no longer influenced by the expiration of wholesale contracts, is expected to average 0.9% or 301 GWh per year.

Variability Due to Weather

Weather has an impact on energy sales and an even greater impact on peak demand. The Public Service system usually experiences its annual peak demand during the month of July. The base forecast assumes normal weather based on a 30-year average of historical temperature data. Because Public Service is aware of the impact of weather on both energy sales and peak demand, Monte Carlo simulations were developed to establish confidence bands around the base forecast to determine the possible extent of these impacts. These confidence bands are provided in detail below.

[19] 1 gigawatt hour (GWh) = 1 million kilowatt hours (kWh).

High and Low Case Forecasts

Development and use of different energy sales and demand forecasts for planning future resource additions is an important aspect of the planning process. Low and high growth sensitivities to the base case were developed for the 2011 ERP. Monte Carlo simulations were developed to establish confidence bands around the base forecast to determine the possible extent of variation in Public Service's service territory's economic growth.

Tables 2.6-1 and 2.6-2 summarize the base, low, and high energy sales and peak demand forecasts.

Actual and Forecasted Demand and Energy

Table 2.6-3 depicts Public Service's base case demand and energy forecast in the context of the last ten years of history. The bold line across the table delineates historical from projected information with 2011 values reflecting actual sales through September.

Table 2.6-3   Actual and Forecasted Summer Peak Demand and Annual Energy

	Summer Peak Demand (MW)	Annual Increase (MW)	Energy Sales (GWh)	Annual Increase (GWh)	
2002	6,057	303	31,432	622	
2003	6,442	385	31,710	278	
2004	6,445	3	32,275	565	
2005	6,912	467	33,921	1,646	
2006	6,656	-257	34,082	161	History
2007	6,940	284	35,544	1,462	
2008	6,692	-248	34,764	-781	
2009	6,160	-532	33,213	-1,550	
2010	6,322	162	33,146	-68	
2011	6,664	342	32,774	-372	
2012	6,391	-272	31,046	-1,728	
2013	6,464	72	31,248	202	
2014	6,521	57	31,550	302	
2015	6,599	78	32,052	502	
2016	6,682	83	32,270	218	
2017	6,743	61	32,635	365	
2018	6,797	54	32,849	214	
2019	6,854	57	33,184	335	
2020	6,905	51	33,652	468	
2021	6,950	46	33,829	177	
2022	6,918	-32	33,742	-87	
2023	6,968	49	33,745	3	
2024	7,026	59	34,096	351	
2025	7,082	56	34,437	341	
2026	7,149	66	34,900	463	
2027	7,212	64	35,204	304	
2028	7,280	68	35,610	406	
2029	7,346	66	36,007	397	
2030	7,412	67	36,314	307	
2031	7,472	60	36,667	353	Forecast
2032	7,531	58	37,109	442	
2033	7,580	50	37,344	236	
2034	7,636	56	37,692	347	
2035	7,696	59	38,129	437	
2036	7,747	52	38,434	304	
2037	7,797	49	38,802	369	
2038	7,843	47	39,260	458	
2039	7,887	44	39,588	328	
2040	7,928	41	39,981	393	
2041	7,966	38	40,457	476	
2042	8,000	35	40,801	344	
2043	8,032	32	41,207	406	
2044	8,060	28	41,692	485	
2045	8,085	25	41,851	158	
2046	8,107	21	42,154	303	
2047	8,118	11	42,537	383	
2048	8,125	7	42,781	244	
2049	8,132	7	43,086	305	
2050	8,156	24	43,472	386	

Energy and Demand Forecasts, 2011-2050

Below are tables presenting the base case energy and demand forecasts for each year within the planning period, 2011-2051:[20]

[20] Public Service did not forecast any sales subject to the jurisdiction of other states.

Table 2.6-4 Base Case: Energy/Coincident Summer and Winter Demand (Including Impacts of DSM Programs)

	Energy Sales (GWh)		Coincident Summer Demand (MW)		Coincident Winter Demand (MW)	
	Retail	Wholesale	Retail	Wholesale	Retail	Wholesale
2011	28,546	4,228	5,913	750	4,445	839
2012	28,458	2,588	5,953	438	4,512	549
2013	28,782	2,466	6,024	440	4,575	552
2014	29,085	2,465	6,081	440	4,638	553
2015	29,383	2,669	6,150	448	4,705	562
2016	29,726	2,545	6,225	457	4,772	574
2017	29,955	2,681	6,277	466	4,819	585
2018	30,223	2,626	6,322	475	4,864	596
2019	30,515	2,669	6,370	484	4,912	608
2020	30,829	2,822	6,412	493	4,953	620
2021	31,061	2,768	6,448	502	4,988	632
2022	31,347	2,396	6,485	434	5,025	421
2023	31,658	2,087	6,531	437	5,071	425
2024	32,040	2,056	6,586	440	5,123	432
2025	32,356	2,081	6,639	443	5,174	439
2026	32,717	2,183	6,702	447	5,228	446
2027	33,057	2,147	6,762	450	5,284	453
2028	33,438	2,172	6,827	453	5,338	460
2029	33,733	2,274	6,889	456	5,393	467
2030	34,075	2,239	6,953	460	5,447	475
2031	34,403	2,264	7,010	463	5,495	483
2032	34,743	2,366	7,064	466	5,542	490
2033	35,014	2,331	7,111	470	5,582	498
2034	35,336	2,356	7,164	473	5,629	506
2035	35,671	2,458	7,219	476	5,677	515
2036	36,010	2,424	7,268	480	5,722	523
2037	36,353	2,449	7,313	483	5,765	531
2038	36,708	2,552	7,356	487	5,807	540
2039	37,071	2,517	7,396	490	5,846	549
2040	37,439	2,542	7,434	494	5,883	558
2041	37,812	2,645	7,468	498	5,918	567
2042	38,190	2,611	7,499	501	5,950	576
2043	38,571	2,636	7,527	505	5,980	586
2044	38,953	2,739	7,552	508	6,008	595
2045	39,146	2,705	7,573	512	6,033	605
2046	39,423	2,731	7,591	516	6,055	615
2047	39,703	2,834	7,598	520	6,075	624
2048	39,981	2,800	7,602	523	6,092	634
2049	40,260	2,826	7,604	527	6,108	643
2050	40,542	2,930	7,608	548	6,125	653

Table 2.6-5A Base Case: Energy/Coincident Summer Demand/Winter Peak Demand by Major Customer Class (Including Impacts of DSM Programs)

	Energy Sales (GWh)					Coincident Summer Peak Demand (MW)					Coincident Winter Peak Demand (MW)				
	Residential	Small & Large C&I	Other	Resale	Total	Residential	Small & Large C&I	Other	Resale	Total	Residential	Small & Large C&I	Other	Resale	Total
2011	9,141	19,172	232	4,228	32,774	2,324	3,599	16	758	6,698	1,966	2,426	53	839	5,284
2012	9,030	19,199	230	2,588	31,046	2,335	3,604	14	438	6,391	1,985	2,472	55	549	5,061
2013	9,101	19,439	241	2,466	31,248	2,363	3,641	20	440	6,464	2,018	2,496	61	552	5,126
2014	9,212	19,624	250	2,465	31,550	2,388	3,672	21	440	6,521	2,051	2,524	62	553	5,191
2015	9,333	19,797	253	2,669	32,052	2,418	3,712	21	448	6,599	2,091	2,547	66	562	5,267
2016	9,474	19,978	273	2,545	32,270	2,452	3,745	28	457	6,682	2,136	2,565	71	574	5,346
2017	9,593	20,084	278	2,681	32,635	2,481	3,768	28	466	6,743	2,179	2,568	72	585	5,404
2018	9,715	20,225	282	2,626	32,849	2,509	3,785	29	475	6,797	2,222	2,569	73	596	5,460
2019	9,834	20,381	300	2,669	33,184	2,536	3,796	39	484	6,854	2,263	2,566	84	608	5,520
2020	9,950	20,565	315	2,822	33,652	2,562	3,811	39	493	6,905	2,304	2,564	85	620	5,573
2021	10,040	20,702	320	2,768	33,829	2,589	3,820	39	502	6,950	2,343	2,559	86	632	5,620
2022	10,144	20,878	325	2,396	33,742	2,616	3,828	40	434	6,918	2,384	2,553	88	421	5,446
2023	10,253	21,075	330	2,087	33,745	2,647	3,843	41	437	6,968	2,426	2,556	89	425	5,496
2024	10,378	21,327	336	2,056	34,096	2,679	3,865	42	440	7,026	2,469	2,563	91	432	5,555
2025	10,493	21,521	341	2,081	34,437	2,712	3,885	43	443	7,082	2,512	2,571	91	439	5,612
2026	10,625	21,745	347	2,183	34,900	2,747	3,912	43	447	7,149	2,557	2,576	95	446	5,674
2027	10,756	21,948	353	2,147	35,204	2,784	3,934	44	450	7,212	2,604	2,584	97	453	5,737
2028	10,894	22,185	358	2,172	35,610	2,820	3,962	45	453	7,280	2,648	2,592	98	460	5,798
2029	11,013	22,356	364	2,274	36,007	2,862	3,981	46	456	7,346	2,697	2,595	101	467	5,860
2030	11,141	22,565	369	2,239	36,314	2,901	4,005	47	460	7,412	2,743	2,601	103	475	5,922

Table 2.6-5B Base Case: Energy/Coincident Summer Demand/Winter Peak Demand by Major Customer Class (Including Impacts of DSM Programs)

	Energy Sales (GWh)					Coincident Summer Peak Demand (MW)					Coincident Winter Peak Demand (MW)				
	Residential	Small & Large C&I	Other	Resale	Total	Residential	Small & Large C&I	Other	Resale	Total	Residential	Small & Large C&I	Other	Resale	Total
2031	11,265	22,763	375	2,264	36,667	2,938	4,024	48	463	7,472	2,787	2,604	104	483	5,978
2032	11,389	22,974	380	2,366	37,109	2,974	4,042	48	466	7,531	2,829	2,607	106	490	6,032
2033	11,496	23,132	385	2,331	37,344	3,006	4,055	49	470	7,580	2,870	2,605	107	498	6,080
2034	11,610	23,335	391	2,356	37,692	3,040	4,073	50	473	7,636	2,912	2,608	108	506	6,135
2035	11,728	23,547	396	2,458	38,129	3,077	4,092	51	476	7,696	2,955	2,612	110	515	6,191
2036	11,848	23,761	402	2,424	38,434	3,112	4,104	51	480	7,747	2,998	2,613	111	523	6,245
2037	11,969	23,977	407	2,449	38,802	3,147	4,114	52	483	7,797	3,040	2,613	112	531	6,297
2038	12,093	24,204	412	2,552	39,260	3,182	4,122	52	487	7,843	3,082	2,612	113	540	6,347
2039	12,217	24,438	417	2,517	39,588	3,217	4,127	53	490	7,887	3,124	2,608	114	549	6,395
2040	12,341	24,677	422	2,542	39,981	3,252	4,129	53	494	7,928	3,165	2,603	115	558	6,441
2041	12,466	24,921	426	2,645	40,457	3,286	4,129	54	498	7,966	3,206	2,596	116	567	6,485
2042	12,590	25,170	430	2,611	40,801	3,320	4,125	54	501	8,000	3,246	2,587	117	576	6,527
2043	12,715	25,422	434	2,636	41,207	3,354	4,119	54	505	8,032	3,286	2,576	118	586	6,566
2044	12,840	25,675	437	2,739	41,692	3,387	4,111	54	508	8,060	3,326	2,563	119	595	6,603
2045	12,962	25,743	440	2,705	41,851	3,420	4,099	55	512	8,085	3,365	2,548	120	605	6,638
2046	13,081	25,899	443	2,731	42,154	3,452	4,084	55	516	8,107	3,404	2,531	120	615	6,670
2047	13,196	26,061	446	2,834	42,537	3,477	4,066	55	520	8,118	3,442	2,512	121	624	6,699
2048	13,307	26,225	448	2,800	42,781	3,502	4,045	55	523	8,125	3,479	2,491	121	634	6,725
2049	13,415	26,394	451	2,826	43,086	3,525	4,024	55	527	8,132	3,516	2,468	124	643	6,751
2050	13,523	26,565	453	2,930	43,472	3,550	4,003	55	548	8,156	3,553	2,444	128	653	6,778

Table 2.6-6 Base Case: Energy and Capacity Sales to Other Utilities (at the Time of Coincident Summer and Winter Peak Demand)

	Energy Sales (GWh)	Coincident Summer Demand (MW)	Coincident Winter Demand (MW)
2011	4,228	758	839
2012	2,588	438	549
2013	2,466	440	552
2014	2,465	440	553
2015	2,669	448	562
2016	2,545	457	574
2017	2,681	466	585
2018	2,626	475	596
2019	2,669	484	608
2020	2,822	493	620
2021	2,768	502	632
2022	2,396	434	421
2023	2,087	437	425
2024	2,056	440	432
2025	2,081	443	439
2026	2,183	447	446
2027	2,147	450	453
2028	2,172	453	460
2029	2,274	456	467
2030	2,239	460	475
2031	2,264	463	483
2032	2,366	466	490
2033	2,331	470	498
2034	2,356	473	506
2035	2,458	476	515
2036	2,424	480	523
2037	2,449	483	531
2038	2,552	487	540
2039	2,517	490	549
2040	2,542	494	558
2041	2,645	498	567
2042	2,611	501	576
2043	2,636	505	586
2044	2,739	508	595
2045	2,705	512	605
2046	2,731	516	615
2047	2,834	520	624
2048	2,800	523	634
2049	2,826	527	643
2050	2,930	548	653

Table 2.6-7 Base Case: Intra-Utility Energy and Capacity Use (at the Time of Coincident Summer and Winter Peak Demand)

	Energy Sales (GWh)		Coincident Summer Demand (MW)		Coincident Winter Demand (MW)	
	Interdpt	Company Use	Interdpt	Company Use	Interdpt	Company Use
2011	3	39	1	8	2	6
2012	3	39	1	8	2	6
2013	3	39	1	8	2	6
2014	3	39	1	8	2	6
2015	3	39	1	8	2	6
2016	3	39	1	8	2	6
2017	3	39	1	8	2	6
2018	3	39	1	8	2	6
2019	3	39	1	8	2	6
2020	3	39	1	8	2	6
2021	3	39	1	8	2	6
2022	3	39	1	8	2	6
2023	3	39	1	8	2	6
2024	3	39	1	8	2	6
2025	3	39	1	8	2	6
2026	3	39	1	8	2	6
2027	3	39	1	8	2	6
2028	3	39	1	8	2	6
2029	3	39	1	8	2	6
2030	3	39	1	8	2	6
2031	3	39	1	8	2	6
2032	3	39	1	8	2	6
2033	3	39	1	8	2	6
2034	3	39	1	8	2	6
2035	3	39	1	8	2	6
2036	3	39	1	8	2	6
2037	3	39	1	8	2	6
2038	3	39	1	8	2	6
2039	3	39	1	8	2	6
2040	3	39	1	8	2	6
2041	3	39	1	8	2	6
2042	3	39	1	8	2	6
2043	3	39	1	8	2	6
2044	3	39	1	8	2	6
2045	3	39	1	8	2	6
2046	3	39	1	8	2	6
2047	3	39	1	8	2	6
2048	3	39	1	8	2	6
2049	3	39	1	8	2	6
2050	3	39	1	8	2	6

Table 2.6-8A Base Case: Losses by Major Customer Class

	Energy Losses (million kWh)				Coincident Summer Demand Losses (MW)				Coincident Winter Demand Losses (MW)			
	Residential	C&I	Other	FERC	Residential	C&I	Other	FERC	Residential	C&I	Other	FERC
2011	702	1,242	17	70	177	241	1	12	151	162	4	14
2012	694	1,243	16	63	176	239	1	11	153	163	4	14
2013	701	1,247	17	64	178	239	1	11	155	164	4	14
2014	708	1,255	17	64	179	240	1	11	158	166	4	14
2015	717	1,264	18	69	181	242	1	12	161	167	5	14
2016	727	1,274	19	66	183	244	2	12	164	168	5	15
2017	737	1,280	19	69	185	244	2	12	168	169	5	15
2018	746	1,288	19	68	187	244	2	12	171	169	5	15
2019	755	1,296	20	69	188	244	2	13	174	168	5	16
2020	763	1,306	21	73	190	244	2	13	177	168	6	16
2021	770	1,315	22	71	191	244	2	13	180	168	6	16
2022	778	1,325	22	59	193	244	2	11	183	168	6	11
2023	786	1,337	22	54	195	244	2	11	187	168	6	11
2024	795	1,351	23	53	197	244	2	12	190	168	6	11
2025	804	1,364	23	54	199	245	2	12	193	169	6	11
2026	814	1,377	23	57	201	246	2	12	197	169	6	12
2027	823	1,389	24	56	203	246	2	12	200	170	6	12
2028	833	1,403	24	56	206	247	2	12	204	170	6	12
2029	843	1,414	24	59	209	248	2	12	207	170	7	12
2030	852	1,426	25	58	211	248	3	12	211	171	7	12

Note: System Loss estimates cannot be made for the transmission and distribution levels because the forecast was not developed at the transmission and distribution voltage level.

Table 2.6-8B Base Case: Losses by Major Customer Class

	Energy Losses (million kWh)				Coincident Summer Demand Losses (MW)				Coincident Winter Demand Losses (MW)			
	Residential	C&I	Other	FERC	Residential	C&I	Other	FERC	Residential	C&I	Other	FERC
2031	862	1,438	25	59	213	249	3	12	214	171	7	13
2032	870	1,448	25	61	216	249	3	12	218	171	7	13
2033	879	1,458	26	60	218	249	3	12	221	171	7	13
2034	888	1,469	26	61	220	249	3	12	224	171	7	13
2035	897	1,481	26	64	222	250	3	12	227	171	7	13
2036	905	1,491	27	63	224	250	3	13	231	172	7	14
2037	915	1,504	27	63	227	249	3	13	234	172	7	14
2038	924	1,517	28	66	229	249	3	13	237	171	7	14
2039	934	1,530	28	65	231	248	3	13	240	171	7	14
2040	941	1,542	28	66	233	248	3	13	243	171	8	14
2041	952	1,557	28	69	235	247	3	13	247	170	8	15
2042	961	1,571	29	67	237	246	3	13	250	170	8	15
2043	971	1,586	29	68	240	244	3	13	253	169	8	15
2044	979	1,598	29	71	242	243	3	13	256	168	8	15
2045	989	1,602	29	70	244	241	3	13	259	167	8	16
2046	998	1,610	30	71	246	239	3	13	262	166	8	16
2047	1,007	1,619	30	73	247	237	3	14	265	165	8	16
2048	1,013	1,625	30	72	248	235	3	14	268	163	8	16
2049	1,023	1,626	30	73	250	232	3	14	270	162	8	17
2050	1,032	1,627	30	76	251	230	3	15	273	160	8	17

Note: System Loss estimates cannot be made for the transmission and distribution levels because the forecast was not developed at the transmission and distribution voltage level.

Table 2.6-9 Base Case: Energy and Peak Demand DSM Savings

	Energy Savings (million kWh)	Coincident Summer Demand Savings (MW)	Coincident Winter Demand Savings (MW)
2011	88	18	13
2012	246	44	27
2013	431	78	44
2014	641	119	67
2015	877	168	95
2016	1,114	220	124
2017	1,351	273	154
2018	1,588	330	185
2019	1,825	389	219
2020	2,062	452	254
2021	2,299	514	289
2022	2,536	577	324
2023	2,773	639	360
2024	3,010	702	395
2025	3,247	765	430
2026	3,484	827	465
2027	3,721	890	500
2028	3,958	952	536
2029	4,195	1,015	571
2030	4,431	1,078	606
2031	0	1,140	641
2032	0	1,203	676
2033	0	1,265	712
2034	0	1,328	747
2035	0	1,391	782
2036	0	1,453	817
2037	0	1,516	852
2038	0	1,579	888
2039	0	1,641	923
2040	0	1,704	958
2041	0	1,766	993
2042	0	1,829	1,028
2043	0	1,892	1,064
2044	0	1,954	1,099
2045	0	2,017	1,134
2046	0	2,079	1,169
2047	0	2,142	1,204
2048	0	2,205	1,240
2049	0	2,267	1,275
2050	0	2,332	1,311

Forecast Overview

Table 2.6-10 presents the base case forecast of native summer peak demand through the resource acquisition period ending in 2018. The forecast is broken into two segments: 1) Retail plus indefinite term resale ("ITR" - contracts that expire beyond the Planning Period) and without defined term resale ("DTR" - contracts that expire within the forecast period) and retail with ITR and DTR which is the total summer native load peak demand. The only DTR customer in the forecast period is Black Hills Colorado. The bold line across the table delineates historical from projected information.

Table 2.6-10 Actual and Forecasted Summer Peak Demand

	Native Peak Demand without Defined Term Resale (MW)	Annual Increase (MW)	Defined Term Resale Demand (MW)	Annual Increase (MW)	Total Summer Native Load Peak Demand (MW)	Annual Increase (MW)	
2007	6,515	281	424	3	6,940	284	
2008	6,413	-102	278	-146	6,692	-248	
2009	5,871	-542	288	10	6,160	-532	Actual
2010	6,014	143	308	20	6,322	162	Data
2011	6,364	349	300	-8	6,664	342	
2012	6,391	28	0	-300	6,391	-272	
2013	6,464	72	0	0	6,464	72	
2014	6,521	57	0	0	6,521	57	
2015	6,599	78	0	0	6,599	78	Forecast
2016	6,682	83	0	0	6,682	83	
2017	6,743	61	0	0	6,743	61	
2018	6,797	54	0	0	6,797	54	

Growth in total native peak demand has been flat over the past five years, with annual gains averaging just 2 MW. However, native peak demand without defined term resale has grown at 0.4% over the time period, average annual increases of 26 MW per year. The projected growth rates through 2018 are considerably stronger. Due to the expiration of wholesale, the growth rate for total native load peak demand is expected to be 0.3%. The growth rate for native peak demand without DTR is expected to be 0.9% the resource acquisition period.

For consistency, native energy sales to the DTR customers were separated from total energy sales in Table 1.6-8. The growth rates for sales are different in both history and forecast. Native sales including the DTR customers decreased by 0.8% annually over the past five years while native sales excluding DTR customers grew 0.4% per year. Native energy sales with DTR customers are is expected to be flat through 2018 as growth from the retail sector and ITR wholesale customers is off-set by the expiration of the DTR wholesale contracts. Native energy sales without the DTR customers are expected to increase by 0.7% annually through 2018.

For both native load peak demand and native energy sales, the forecast without the DTR customers presents a clearer view of the expected patterns of growth for the retail and resale customers that will be served throughout the resource acquisition period.

Table 2.6-11 Actual and Forecasted Annual Energy Sales

	Annual Energy Sales without Defined Term Resale (GWh)	Annual Increase (GWh)	Annual Defined Term Resale Energy Sales (GWh)	Annual Increase (GWh)	Total Annual Energy Sales (GWh)	Annual Increase (GWh)	
2007	32,362	1,630	3,182	-168	35,544	1,462	
2008	32,551	189	2,213	-969	34,764	-781	
2009	31,439	-1,112	1,774	-438	33,213	-1,550	Actual Data
2010	31,401	-38	1,745	-29	33,146	-68	
2011	31,280	-121	1,494	-251	32,774	-372	
2012	30,907	-374	139	-1,355	31,046	-1,728	
2013	31,248	341	0	-139	31,248	202	
2014	31,550	302	0	0	31,550	302	
2015	32,052	502	0	0	32,052	502	Forecast
2016	32,270	218	0	0	32,270	218	
2017	32,635	365	0	0	32,635	365	
2018	32,849	214	0	0	32,849	214	

Forecast Methodologies

The following discussion describes the methods Public Service uses to forecast each of the various customer classes, which make up the total Public Service energy and demand forecasts.

Public Service uses monthly historical customer, sales and peak demand data by rate class to develop its forecasts. Forecasted economic and demographic data are obtained from IHS Global Insight, Inc.

Energy Sales Forecast

Public Service's residential sales and commercial and industrial sales forecasts are developed using a Statistically-Adjusted End-Use ("SAE") modeling approach. The SAE method entails specifying energy use as a function of the primary end-use variables (heating, cooling, and base use) and the factors that affect these end-use energy requirements.

The SAE residential sales forecast is calculated as the product of average use and customer forecasts. The SAE modeling approach consists of regressions for average use per customer and number of customers. The use per customer regression model is estimated using monthly historical sales per customer, weather, economics, price, and appliance saturation and efficiency trend data. Customer growth is strongly correlated with growth in state housing stock. Therefore, the number of customers is forecasted as a function of housing stock projections.

End-use concepts are incorporated in the average use per customer model. Average use is defined as a function of heating, cooling, and base use requirements, as shown below. The term *e* is the model error term.

Average Use = Heating + Cooling + Base + ***e***

Each of these elements of average use is defined in terms of both an appliance index variable, which indicates relative saturation and efficiency of the stock of appliances, and a utilization variable, which reflects how the stock is utilized. The end-use variables are defined as:

Heating = HeatIndex * HeatUse
Cooling = CoolIndex * CoolUse
Base = BaseIndex * BaseUse

The indices are calculated as the ratio of the appliance saturation and average efficiency of the existing stock. To generate a relative index, the ratio is divided by the estimated value for 2006. Thus, the index has a value of 1.0 in 2006. The indices reflect both changes in saturation resulting from end-use competition and improvements in appliance efficiency standards. For example, if gas heating gains market share, the electric heating saturation will decline, resulting in a decline in the heating index variable. Similarly, improvements in electric heating efficiency will also contribute to a lower heating index. The trend towards greater saturation of central air conditioning has the opposite effect, contributing to an increasing cooling index over time. Air conditioning efficiency gains mitigate this increase. Appliance trends in other end-uses such as water heating, cooking, refrigeration, and miscellaneous loads are captured in the base index.

The utilization variables (CoolUse, HeatUse, and BaseUse) are designed to capture energy demand driven by the use of the appliance stock. For the residential sector, the primary factors that impact appliance use are weather conditions (as measured by heating and cooling degree days), electricity prices, household income, household size, and hours of daylight. The utilization variables are defined as:

COOLUSE = (PRICE^(-0.2)) * (INCOME_PER_HOUSEHOLD^0.2)
*(HOUSEHOLD_SIZE^0.01) * COOLING_DEGREE_DAYS

HEATUSE = (PRICE^(-0.2)) * (INCOME_PER_HOUSEHOLD^0.2) *(HOUSEHOLD_SIZE^0.01) * HEATING_DEGREE_DAYS

BASEUSE = (PRICE^(-0.2)) * (INCOME_PER_HOUSEHOLD^0.2) *(HOUSEHOLD_SIZE^0.01) * (HOURS_OF_LIGHT^(-0.2))

In this functional form, the values shown in the specifications are, in effect, elasticities. The elasticities give the percent change in the utilization variables (CoolUse, HeatUse, and BaseUse) given a 1% change in the economic variables (Price, Income per Household, and Household Size). The elasticities are inferred from the Electric Power Research Institute ("EPRI") residential end-use model REEPS.

The forecast model is estimated by regressing monthly average residential usage on Cooling Use, Heating Use, Base Use, and monthly seasonal variables for all months except January, July, and August. The regression model effectively calibrates the end-use concepts to actual residential average use. Monthly seasonal variables for each month are included to account for non-weather-related seasonal factors. The forecast model results are adjusted to reflect the expected incremental impact of residential DSM programs, reductions in sales that can be attributed to distributed solar generation, and the expected impacts from the residential tiered rate structure that is effective from June through September each year.

The same general approach is used to construct the commercial and industrial sales forecast model. For this model, sales can again be decomposed into heating, cooling and base use. The end-use variables Heating, Cooling and Base are structured in a manner similar to those used in the residential model and are defined as the product of a variable that reflects technology stock and efficiency (Index) and a variable that captures stock utilization (Use).

For the commercial and industrial sector, saturation and efficiency trends can be captured by the change in annual energy intensities (kWh per square foot). These intensity trends are estimated using the EPRI commercial end-use model COMMEND. The Heating Index, Cooling Index, and Base Index have values of 1.0 in 2000. Increasing saturation levels drive an index higher, while improvements in stock efficiency or decreasing saturation levels lower the value of the index.

Stock utilization is a function of electricity prices, business activity (as measured by Colorado Gross State Product), heating degree days, cooling degree days, and hours of light. The utilization variables are specified as:

COOLUSE = (PRICE^(-0.2)) * (CO_GROSS_STATE_PRODUCT^0.3) * COOLING_DEGREE_DAYS

HEATUSE = (PRICE^(-0.2)) * (CO_GROSS_STATE_PRODUCT^0.3) * HEATING_DEGREE_DAYS

BASEUSE = (PRICE^(-0.2)) * (CO_GROSS_STATE_PRODUCT^0.6) * (HOURS_OF_LIGHT^(-0.2))

The forecast model is then estimated by regressing monthly commercial and industrial sales on Cooling, Heating, Base, monthly billing cycle days, a variable that quantifies identified new large customer load (MW), a monthly seasonal variable for each month, a variable to account for the implementation of the new billing system in 2004, and a binary variable for July and August 2004, and January 2007. The regression model effectively calibrates the end-use concepts to actual commercial and industrial sales. In this case, the Heating variable is excluded from the regression because it did not provide significant explanatory value. A variable for identified new large customer loads was added to explain growth in Public Service's service territory that was greater than the state-wide growth documented in the historical Colorado Gross State Product. The monthly seasonal variables for each month are included to account for non-weather-related seasonal factors. Binary variables for July and August 2004, and January 2007, are included to account for unusual billing activity. The model results are adjusted to reflect the expected incremental impact of commercial and industrial DSM programs, distributed solar generation, and new load additions as identified by the large commercial and industrial customer account managers.

Public authority sales are forecasted using a regression model that is based on the same Base variable developed for the commercial and industrial sector and various monthly binary variables. The public authority model includes a binary variable for the latest extension of light rail service for the Regional Transportation District in 2002 and 2006.

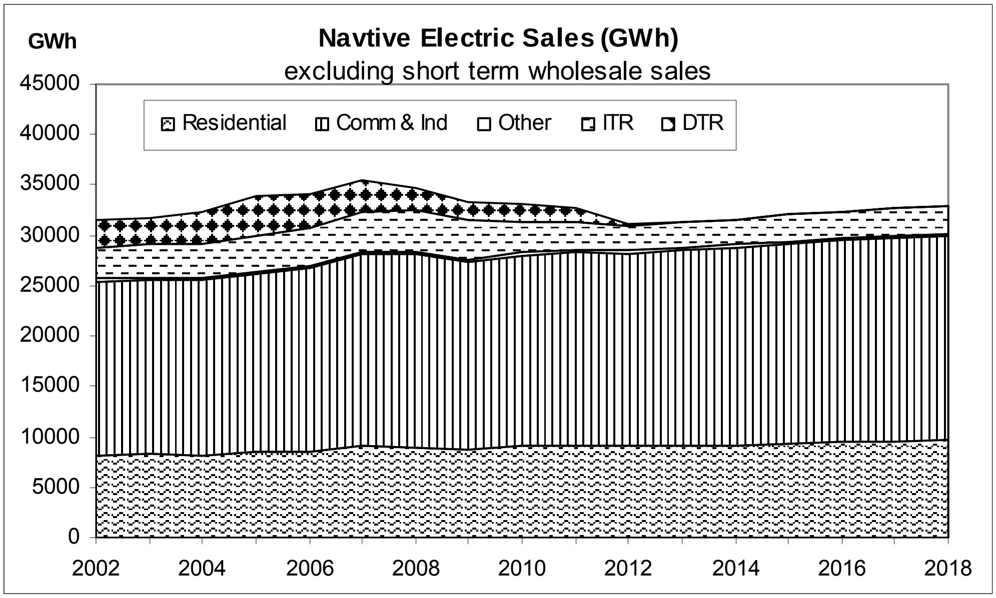
The forecast of street lighting sales for the test year is based on trend forecasts of light counts or customer counts by rate and wattage. The light counts and/or customer counts are then used to develop the sales forecast by rate and wattage based on watts per light and monthly hours of usage.

The interdepartmental sales forecast is developed using a regression model with seasonal binary variables, a binary variable to account for the implementation of the new billing system in 2004, and a binary variable for December 2008 and September 2000.

Forecasts for sales to resale customers are received from Public Service's wholesale customers.

There is one firm wholesale customer contract with Public Service which will end during the resource acquisition period. After that contract end date, the energy sales forecast for that customer drops to zero. The forecast for sales to Black Hills is based on contractual requirements.

Figure 2.6-3 Native Electric Sales (GWh)



Demand Forecast

Residential coincident peak demand is expected to increase in response to changes to residential energy requirements. For the residential demand regression model, residential energy requirements are defined as a 12-month moving average of monthly residential sales. The moving average calculation removes the monthly sales cyclical pattern. Efficiency improvements captured in the residential sales model are assumed to have the same impact on residential peak demand. Since peak demand does not necessarily grow at the same rate as the underlying sales, an end-use saturation term interacting with peak-day weather conditions and customer counts is also included in the model. This variable is defined as:

Peak_Day_Cooling_Degree_Days *Customer Counts* CoolIndex

The cooling index is the same index used in the residential average use per customer model. With the cooling index variable the sensitivity to peak-day weather changes as residential cooling saturation and efficiency changes.

Also included in the residential peak model are peak day heating degree days and binary variables to remove months with data anomalies (October 2005, April 2006, April 2007, May 2007, October 2007, September 2008, and October 2010).

The commercial and industrial (nonresidential) coincident peak demand forecast is developed using a regression model similar to the residential peak model. Historical commercial and industrial coincident peaks are regressed against commercial and industrial energy requirements defined as the 12-month moving average of commercial and industrial sales. Also included in the model is a variable that allows peak demand to change at a different rate than sales. This variable, which interacts peak day weather with commercial-industrial customers, reflects increasing cooling usage as customer counts increase. In addition, the model contains non-farm employment and a binary variable to remove September 2008 from the regression.

Information from the Xcel Managed Account Sales group regarding Public Service's largest commercial and industrial customers may be used to make adjustments to the modeled peak demand forecasts.

Forecasts of peak demand for each REA and municipality are received from the respective wholesale customers. Forecasts of the capacity required by these customers coincident with the system peak are developed from following sources of information.

1. Historical loads for Public Service sales to these customers coincident with the Public Service system peak are provided by Xcel Energy's Load Research Department.

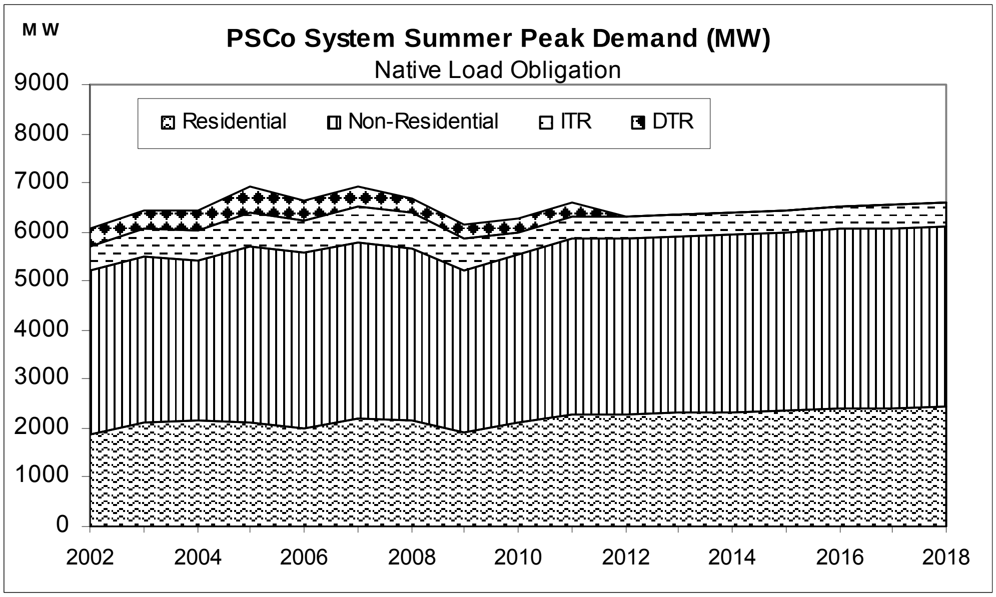
2. Monthly billing reports provide historical data of energy and capacity sales itemized by the utility providing the power, the total non-coincident peak demand for the month, and the portion of that peak demand allocated to WAPA.

A forecast of the capacity required by each of these customers coincident with the Public Service system peak is developed using the trends present in the non-coincident peak demand forecasts, the historical coincident loads, and information from the billing reports regarding WAPA capacity allocations and the total load coincident with the Public Service system peak.

Forecasts for coincident demand for Black Hills are based on contractual requirements.

Coincident peak demand forecasts for the interruptible load are provided by Xcel Energy's Load Research Department. The components of this forecast are the primary, secondary, and transmission voltage Interruptible contracted loads and the Residential Saver's Switch program.

Figure 2.6-4 Native Peak Demand (MW)



Variability Due to Weather

Weather has an impact on energy sales and an even greater impact on peak demand. The Public Service system usually experiences its annual peak demand during the month of July. The base forecast assumes normal weather based on 30-year average of peak day weather in the future. In order to quantify the possible outcomes of weather variation from the 30-year average weather, Monte Carlo simulations have been developed to establish confidence bands around the base forecast. The probability distributions for the simulation runs for both sales and demand were based on 30 years of historical weather data for Denver. Table 2.6-12 provides the resulting confidence bands at the level of 1.00 standard deviation or 70% probability bandwidth and 1.65 standard deviations or 90% probability bandwidth above and below the base case forecast of native load peak demand. Table 2.6-13 provides the confidence bands above and below the annual native energy sales forecast. Graphs of the peak demand and sales confidence bands are presented in Figure 2.6-4 and Figure 2.6-5.

Table 2.6-12 Native Peak Demand Weather Variability

	Coincident Summer Peak Demand (MW)					Coincident Winter Peak Demand (MW)				
	+1.65 Std Dev	+1 Std Dev	Base	-1 Std Dev	-1.65 Std Dev	+1.65 Std Dev	+1 Std Dev	Base Case	-1 Std Dev	-1.65 Std Dev
2011	7,026	6,879	6,628	6,367	6,221	5,662	5,516	5,284	5,050	4,916
2012	6,803	6,652	6,391	6,130	5,975	5,406	5,281	5,061	4,833	4,701
2013	6,884	6,730	6,464	6,200	6,048	5,481	5,346	5,126	4,900	4,770
2014	6,939	6,786	6,521	6,256	6,098	5,554	5,414	5,191	4,965	4,838
2015	7,009	6,856	6,599	6,334	6,175	5,621	5,490	5,267	5,045	4,912
2016	7,100	6,946	6,682	6,424	6,265	5,700	5,571	5,346	5,123	4,998
2017	7,151	7,006	6,743	6,483	6,334	5,754	5,629	5,404	5,183	5,054
2018	7,216	7,060	6,797	6,540	6,396	5,815	5,686	5,460	5,238	5,114
2019	7,262	7,107	6,854	6,597	6,444	5,868	5,741	5,520	5,296	5,169
2020	7,302	7,155	6,905	6,646	6,498	5,932	5,798	5,573	5,354	5,217
2021	7,359	7,203	6,950	6,692	6,544	5,971	5,841	5,620	5,396	5,268
2022	7,321	7,171	6,918	6,666	6,524	5,786	5,654	5,446	5,230	5,108
2023	7,365	7,219	6,968	6,717	6,568	5,831	5,712	5,496	5,285	5,160
2024	7,426	7,274	7,026	6,771	6,620	5,894	5,766	5,555	5,340	5,212
2025	7,486	7,336	7,082	6,833	6,687	5,949	5,824	5,612	5,397	5,267
2026	7,551	7,406	7,149	6,897	6,754	6,015	5,890	5,674	5,464	5,338
2027	7,616	7,469	7,212	6,965	6,818	6,080	5,952	5,737	5,520	5,392
2028	7,675	7,527	7,280	7,025	6,875	6,147	6,014	5,798	5,579	5,453
2029	7,751	7,600	7,346	7,093	6,941	6,204	6,075	5,860	5,645	5,519
2030	7,818	7,667	7,412	7,156	7,007	6,275	6,146	5,922	5,706	5,571
2031	7,881	7,728	7,472	7,218	7,067	6,333	6,194	5,978	5,758	5,622
2032	7,937	7,781	7,531	7,273	7,125	6,381	6,255	6,032	5,809	5,676
2033	7,984	7,835	7,580	7,324	7,175	6,429	6,298	6,080	5,858	5,725
2034	8,041	7,896	7,636	7,384	7,238	6,490	6,359	6,135	5,909	5,775
2035	8,096	7,953	7,696	7,438	7,283	6,547	6,416	6,191	5,961	5,825
2036	8,146	8,005	7,747	7,489	7,333	6,601	6,469	6,245	6,012	5,875
2037	8,193	8,054	7,797	7,538	7,381	6,653	6,521	6,297	6,061	5,924
2038	8,238	8,100	7,843	7,585	7,427	6,703	6,571	6,347	6,108	5,971
2039	8,279	8,144	7,887	7,629	7,470	6,751	6,619	6,395	6,153	6,016
2040	8,318	8,185	7,928	7,670	7,510	6,796	6,665	6,441	6,197	6,059
2041	8,353	8,222	7,966	7,709	7,548	6,840	6,708	6,485	6,238	6,100
2042	8,385	8,257	8,000	7,744	7,583	6,881	6,749	6,527	6,277	6,140
2043	8,414	8,288	8,032	7,776	7,614	6,920	6,788	6,566	6,314	6,177
2044	8,439	8,316	8,060	7,805	7,643	6,956	6,824	6,603	6,349	6,212
2045	8,460	8,340	8,085	7,831	7,668	6,990	6,858	6,638	6,382	6,244
2046	8,478	8,360	8,107	7,853	7,690	7,021	6,890	6,670	6,412	6,275
2047	8,485	8,370	8,118	7,866	7,702	7,048	6,917	6,699	6,438	6,302
2048	8,488	8,376	8,125	7,874	7,711	7,073	6,942	6,725	6,463	6,326
2049	8,491	8,381	8,132	7,883	7,719	7,097	6,967	6,751	6,487	6,350
2050	8,512	8,405	8,156	7,908	7,743	7,122	6,992	6,778	6,511	6,376

Table 2.6-13 Annual Native Energy Sales Weather Variability

	Energy Sales (million kWh)				
	+1.65 Std Dev	+1 Std Dev	Base	-1 Std Dev	-1.65 Std Dev
2011	34,601	33,920	32,774	31,636	30,974
2012	32,874	32,192	31,046	29,908	29,240
2013	33,123	32,430	31,248	30,080	29,396
2014	33,424	32,725	31,550	30,377	29,693
2015	33,917	33,223	32,052	30,887	30,199
2016	34,126	33,428	32,270	31,109	30,437
2017	34,481	33,793	32,635	31,477	30,799
2018	34,685	34,006	32,849	31,705	31,033
2019	35,016	34,338	33,184	32,035	31,367
2020	35,488	34,807	33,652	32,502	31,837
2021	35,660	34,979	33,829	32,687	32,020
2022	35,545	34,876	33,742	32,615	31,954
2023	35,530	34,873	33,745	32,625	31,977
2024	35,872	35,216	34,096	32,973	32,325
2025	36,216	35,562	34,437	33,322	32,665
2026	36,687	36,020	34,900	33,780	33,124
2027	36,983	36,319	35,204	34,086	33,438
2028	37,405	36,731	35,610	34,497	33,838
2029	37,797	37,129	36,007	34,891	34,242
2030	38,094	37,434	36,314	35,204	34,543
2031	38,446	37,780	36,667	35,552	34,899
2032	38,890	38,225	37,109	35,995	35,343
2033	39,120	38,463	37,344	36,221	35,578
2034	39,465	38,808	37,692	36,581	35,924
2035	39,917	39,251	38,129	37,013	36,351
2036	40,219	39,553	38,434	37,318	36,657
2037	40,589	39,921	38,802	37,686	37,025
2038	41,050	40,381	39,260	38,140	37,479
2039	41,377	40,707	39,588	38,469	37,808
2040	41,771	41,100	39,981	38,862	38,201
2041	42,251	41,578	40,457	39,335	38,673
2042	42,593	41,919	40,801	39,679	39,018
2043	42,999	42,325	41,207	40,084	39,424
2044	43,488	42,811	41,692	40,567	39,906
2045	43,636	42,962	41,851	40,732	40,075
2046	43,934	43,262	42,154	41,038	40,383
2047	44,315	43,643	42,537	41,422	40,769
2048	44,551	43,881	42,781	41,671	41,020
2049	44,851	44,182	43,086	41,979	41,331
2050	45,234	44,565	43,472	42,366	41,720

Figure 2.6-5 Native Peak Demand Weather Confidence Bands (MW)

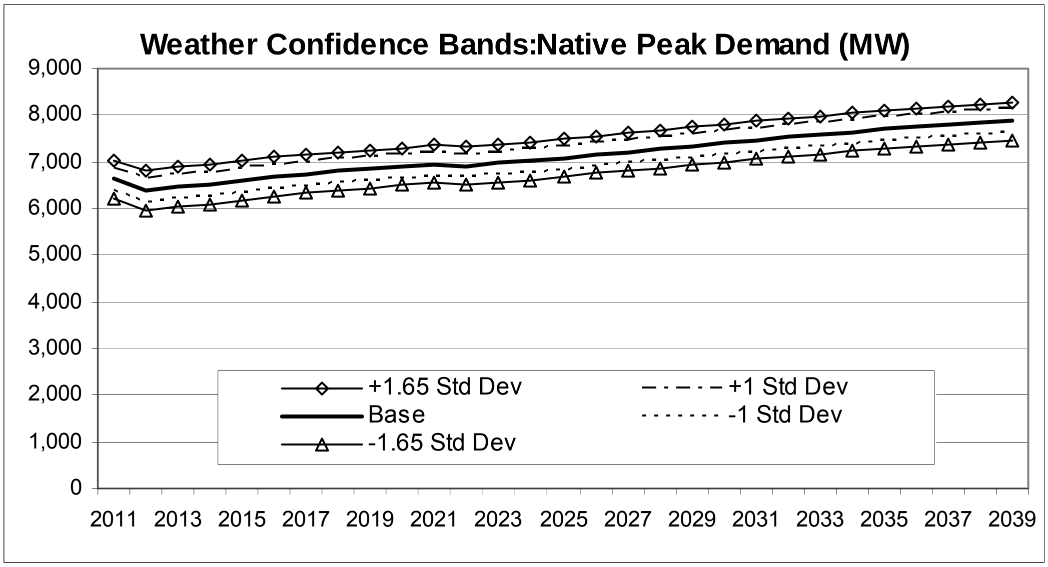
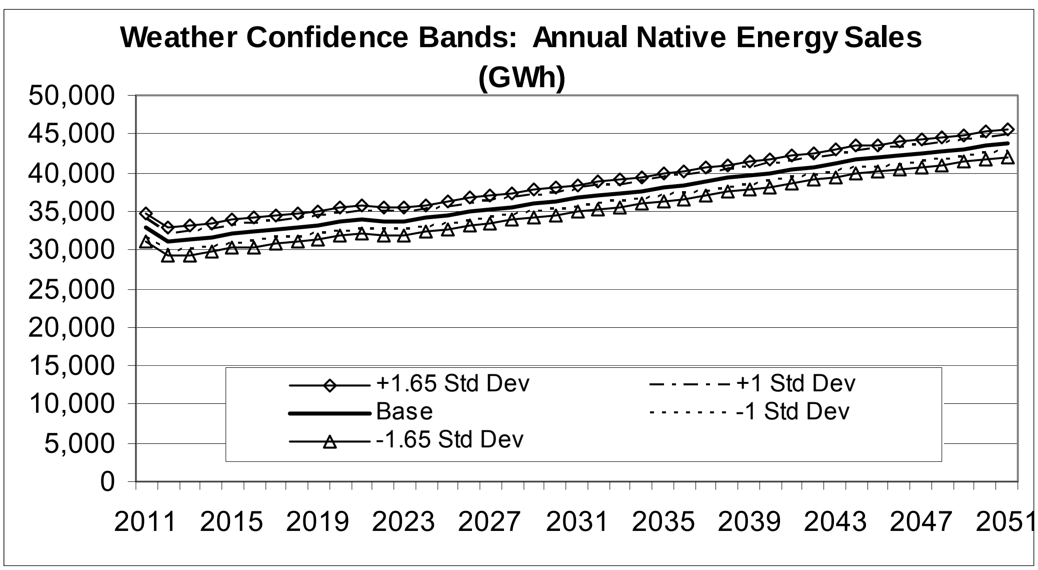


Figure 2.6-6 Native Sales Weather Confidence Bands (GWH)



High Growth Forecast

Public Service's high energy sales forecast is based on a Monte Carlo simulation of the energy sales forecast with probabilistic inputs for the main economic drivers of the forecast model and for model error. The primary component of the high sales scenario is the forecast level from the simulation that represents the upper limit of a one standard deviation wide confidence band.

The resulting high energy sales forecast grows 1.0% annually over the next 40 years, from 32,774 GWh in 2011, to 49,482 GWh in 2051. High energy sales growth over the next 7 years is anticipated to average 0.8% annually with sales of 34,616 GWh in 2018.

Public Service's high summer native load peak demand forecast grows from 6,664 MW in 2011 to 9,414 MW in 2051, an average annual growth rate of 0.9%. Short-term annual growth is expected to be 1.1% over the next 7 years. The Base Case forecast indicates 0.3% annual growth through 2018 and 0.5% through 2051.

The forecasted high peak demands and high sales are contained in Figures 2.6-7 and 2.6-8 and listed in Tables 2.6-14 and 2.6-15.

Low Growth Forecast

Public Service's low energy sales forecast is based on a Monte Carlo simulation of the energy sales forecast with probabilistic inputs for the main economic drivers of the forecast model and for model error. The primary component of the low sales scenario is the forecast level from the simulation that represents the lower limit of a one standard deviation wide confidence band.

The resulting low native energy sales forecast grows 0.4% annually over the next 40 years, from 32,774 GWh in 2011, to 38,048 GWh in 2051. The low scenario energy sales growth over the next 7 years is anticipated to average -0.8% annually with sales of 31,067 GWh in 2018.

Public Service's low summer native load peak demand forecast grows from 6,664 MW in 2011 to 7,177 MW in 2051, an average annual growth rate of 0.2%. The low short-term annual growth is expected to be -0.6% over the next 7 years, with peak demand of 6,386 in 2018.

The forecasted low peak demands and low sales are illustrated in Figures 2.6-7 and 2.6-8 and listed in Tables 2.6-14 and 2.6-15.

Figure 2.6-7 Base Case, High and Low Peak Energy Sales Forecast Comparison – Base, High, Low

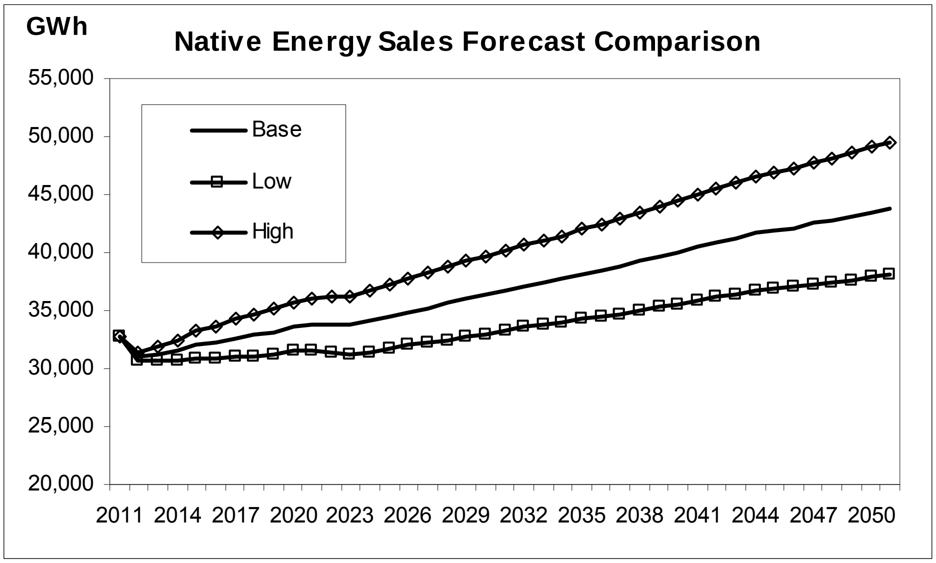


Figure 2.6-8 Base Case, High and Low Peak Demand Forecast

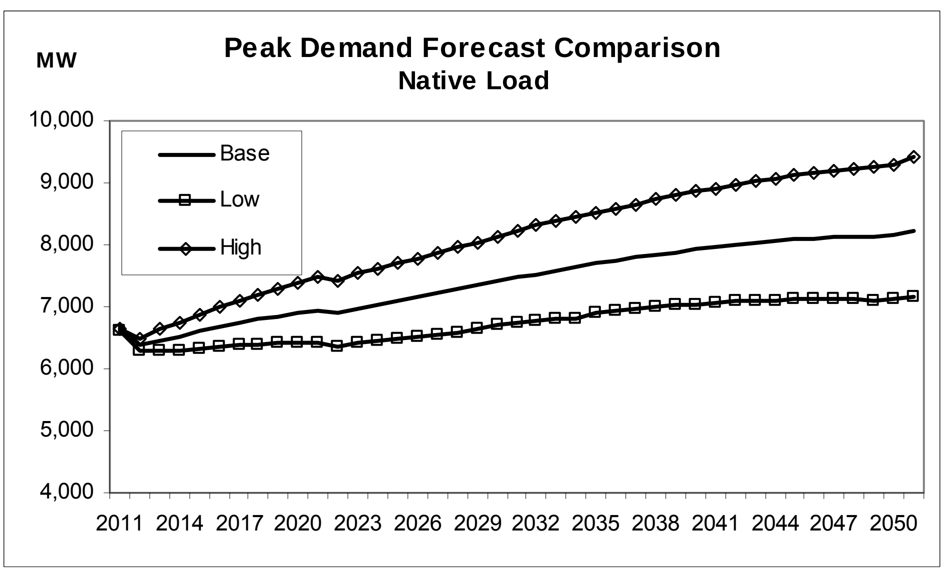


Table 2.6-14 Base Case, High, and Low Sales of Energy (Including Impacts of DSM Programs)

	Base	Low	High
2011	32,774	32,771	32,779
2012	31,046	30,706	31,387
2013	31,248	30,606	31,865
2014	31,550	30,650	32,460
2015	32,052	30,881	33,210
2016	32,270	30,892	33,654
2017	32,635	31,039	34,225
2018	32,849	31,067	34,616
2019	33,184	31,228	35,129
2020	33,652	31,538	35,770
2021	33,829	31,558	36,095
2022	33,742	31,338	36,126
2023	33,745	31,228	36,238
2024	34,096	31,461	36,712
2025	34,437	31,671	37,210
2026	34,900	31,996	37,780
2027	35,204	32,222	38,228
2028	35,610	32,489	38,732
2029	36,007	32,777	39,248
2030	36,314	32,969	39,650
2031	36,667	33,212	40,112
2032	37,109	33,547	40,676
2033	37,344	33,713	40,996
2034	37,692	33,931	41,447
2035	38,129	34,270	41,990
2036	38,434	34,475	42,398
2037	38,802	34,735	42,877
2038	39,260	35,074	43,458
2039	39,588	35,296	43,895
2040	39,981	35,575	44,407
2041	40,457	35,926	45,013
2042	40,801	36,158	45,472
2043	41,207	36,444	46,003
2044	41,692	36,799	46,625
2045	41,851	36,864	46,881
2046	42,154	37,056	47,302
2047	42,537	37,317	47,813
2048	42,781	37,455	48,169
2049	43,086	37,646	48,595
2050	43,472	37,906	49,114

Table 2.6-15 Base Case, High and Low Coincident Summer and Winter Peak Demand (Including Impacts of DSM Programs)

	Coincident Summer Demand (MW)			Coincident Winter Demand (MW)		
	Base	**Low**	**High**	**Base**	**Low**	**High**
2011	6,664	6,607	6,658	5,284	5,275	5,299
2012	6,391	6,297	6,485	5,061	4,983	5,145
2013	6,464	6,295	6,630	5,126	4,977	5,265
2014	6,521	6,302	6,734	5,191	4,993	5,389
2015	6,599	6,315	6,882	5,267	5,023	5,513
2016	6,682	6,362	7,012	5,346	5,067	5,631
2017	6,743	6,375	7,112	5,404	5,086	5,724
2018	6,797	6,386	7,197	5,460	5,112	5,807
2019	6,854	6,413	7,305	5,520	5,133	5,912
2020	6,905	6,431	7,385	5,573	5,160	5,980
2021	6,950	6,428	7,478	5,620	5,166	6,063
2022	6,918	6,362	7,434	5,446	5,004	5,897
2023	6,968	6,407	7,535	5,496	5,017	5,960
2024	7,026	6,460	7,606	5,555	5,060	6,057
2025	7,082	6,487	7,709	5,612	5,105	6,139
2026	7,149	6,515	7,779	5,674	5,125	6,215
2027	7,212	6,559	7,857	5,737	5,180	6,298
2028	7,280	6,586	7,965	5,798	5,216	6,381
2029	7,346	6,648	8,035	5,860	5,269	6,476
2030	7,412	6,700	8,115	5,922	5,305	6,548
2031	7,472	6,734	8,214	5,978	5,349	6,611
2032	7,531	6,773	8,310	6,032	5,380	6,699
2033	7,580	6,790	8,384	6,080	5,399	6,776
2034	7,636	6,800	8,447	6,135	5,456	6,838
2035	7,696	6,895	8,512	6,191	5,471	6,904
2036	7,747	6,930	8,587	6,245	5,503	6,976
2037	7,797	6,961	8,659	6,297	5,533	7,046
2038	7,843	6,991	8,728	6,347	5,562	7,114
2039	7,887	7,017	8,795	6,395	5,589	7,180
2040	7,928	7,041	8,859	6,441	5,613	7,244
2041	7,966	7,063	8,919	6,485	5,636	7,306
2042	8,000	7,081	8,976	6,527	5,657	7,366
2043	8,032	7,097	9,030	6,566	5,676	7,423
2044	8,060	7,109	9,080	6,603	5,692	7,478
2045	8,085	7,119	9,127	6,638	5,706	7,530
2046	8,107	7,125	9,170	6,670	5,719	7,579
2047	8,118	7,122	9,201	6,699	5,728	7,625
2048	8,125	7,116	9,228	6,725	5,734	7,668
2049	8,132	7,109	9,254	6,751	5,740	7,710
2050	8,156	7,118	9,301	6,778	5,747	7,754

Forecast Accuracy

Public Service reviews its demand and energy forecasts for accuracy annually. Overall, forecast accuracy is better in the short term than in the long term.

Tables 2.6-16 through 2.6-24 on the following pages compare the actual energy sales and demand forecasts to the forecasted sales and system demands, as required by the Electric Resource Planning rules. Figures 2.6-9 through 2.6-13 contain a graphical description of the forecasts.

Table 2.6-16 Native Energy Sales Forecast Comparison (GWh)

	Actual Energy Sales	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast
2006	34,082					34,041
2007	35,544				34,201	34,698
2008	34,764			34,523	34,027	34,542
2009	33,213		34,143	35,124	34,666	35,310
2010	33,146	33,398	33,093	34,858	33,612	35,801

Table 2.6-17 Forecast Sales less Actual Sales (GWh)

	Actual less Forecast (GWh)					Percent Difference				
	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast
2006					41					0.12%
2007				1,343	846				3.93%	2.44%
2008			241	737	221			0.70%	2.17%	0.64%
2009		-929	-1,910	-1,453	-2,097		-2.72%	-5.44%	-4.19%	-5.94%
2010	-252	53	-1,712	-466	-2,655	-0.75%	0.16%	-4.91%	-1.39%	-7.42%

Table 2.6-18 Coincident Summer Demand Forecast Comparison (MW)

	Actual Demand	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast
2006	6,656					6,755
2007	6,940				6,869	6,926
2008	6,692			6,910	6,861	6,921
2009	6,160		6,863	7,066	7,039	7,102
2010	6,322	6,490	6,711	7,067	6,925	7,115

Table 2.6-19 Forecast Demand less Actual Summer Native Peak Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast
2006					-99					-1.46%
2007				71	14				1.03%	0.20%
2008			-218	-169	-229			-3.16%	-2.47%	-3.31%
2009		-703	-906	-879	-942		-10.24%	-12.82%	-12.49%	-13.27%
2010	-168	-389	-745	-603	-793	-2.59%	-5.79%	-10.54%	-8.71%	-11.15%

Table 2.6-20 Weather Normalized Coincident Summer Demand Forecast Comparison (MW)

	Weather Normal Demand	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast
2006	6,542					6,755
2007	6,766				6,869	6,926
2008	6,505			6,910	6,861	6,921
2009	6,384		6,863	7,066	7,039	7,102
2010	6,415	6,490	6,711	7,067	6,925	7,115

Table 2.6-21 Forecast Demand less Actual Summer Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast
2006					-213					-3.15%
2007				-103	-160				-1.51%	-2.31%
2008			-405	-356	-416			-5.87%	-5.20%	-6.01%
2009		-479	-682	-655	-718		-6.98%	-9.65%	-9.30%	-10.12%
2010	-75	-296	-652	-510	-700	-1.16%	-4.40%	-9.22%	-7.36%	-9.84%

Table 2.6-22 Coincident Winter Demand Forecast Comparison (MW)

	Actual Demand	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast
2006	5,747					5,596
2007	5,822				5,731	5,719
2008	5,818			5,767	5,738	5,704
2009	5,961		5,499	5,684	5,886	5,843
2010	5,312	5,607	5,588	5,918	5,742	5,820

Table 2.6-23 Forecast Demand less Actual Winter Demand (MW)

	Actual less Forecast (MW)					Percent Difference				
	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast	2010 Forecast	2009 Forecast	2008 Forecast	2007 Forecast	2006 Forecast
2006					151					2.71%
2007				91	103				1.59%	1.80%
2008			51	80	114			0.89%	1.39%	2.00%
2009		462	277	75	118		8.40%	4.87%	1.27%	2.03%
2010	-295	-275	-606	-430	-508	-5.26%	-4.93%	-10.24%	-7.48%	-8.73%

Figure 2.6-9 Forecast Comparison to Actual Native Energy Sales

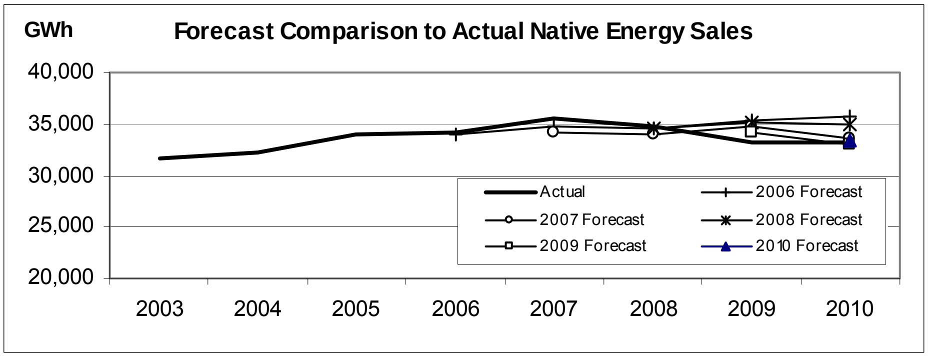


Figure 2.6-10 Forecast Comparison to Actual Summer Native Peak Demand

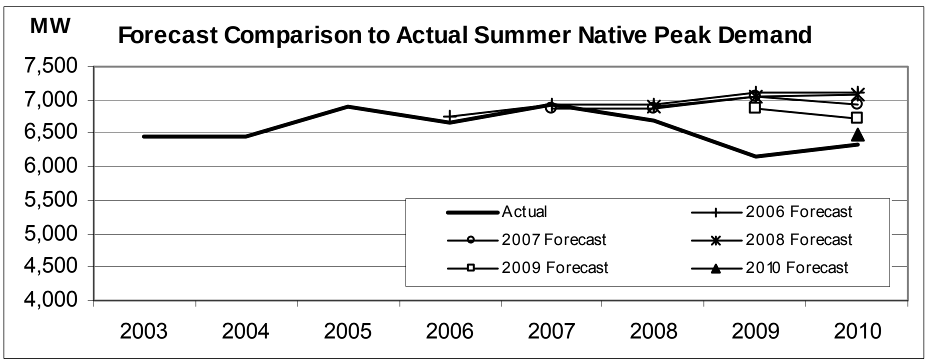


Figure 2.6-11 Forecast Comparison to Actual Winter Native Peak Demand

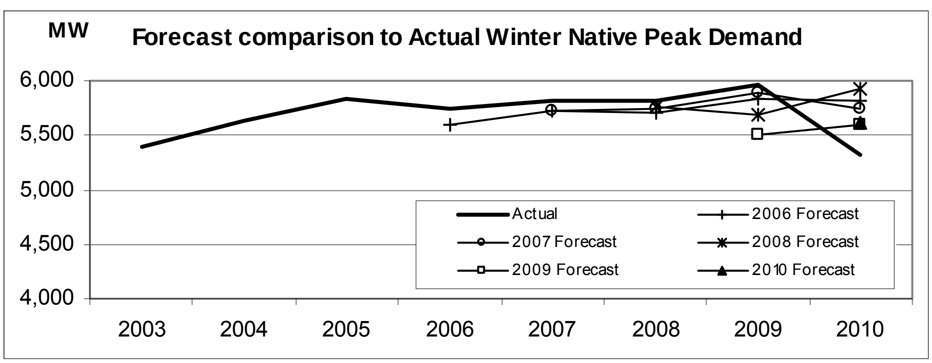


Table 2.6-24 2007 ERP Forecast vs. 2011 ERP Forecast

Year	Summer Coincident Peak Demand (MW)		Annual Energy Sales (GWh)	
	2007 RP Forecast	2011 RP Forecast	2007 RP Forecast	2011 RP Forecast
2007	6,698		34,265	
2008	6,650		34,027	
2009	6,773		34,666	
2010	6,603		33,613	
2011	6,722	6,664	34,091	32,774
2012	6,545	6,391	32,850	31,046
2013	6,694	6,464	33,306	31,248
2014	6,854	6,521	34,054	31,550
2015	7,025	6,599	34,835	32,052
2016	7,206	6,682	35,736	32,270
2017	7,402	6,743	36,501	32,635
2018	7,593	6,797	37,332	32,849
2019	7,792	6,854	38,173	33,184
2020	7,997	6,905	39,082	33,652
2021	8,241	6,950	39,931	33,829
2022	8,489	6,918	40,849	33,742
2023	8,735	6,968	41,787	33,745
2024	8,995	7,026	42,824	34,096
2025	9,268	7,082	43,790	34,437
2026	9,536	7,149	44,821	34,900
2027	9,812	7,212	45,876	35,204
2028	10,095	7,280	46,973	35,610
2029	10,383	7,346	47,983	36,007
2030	10,665	7,412	49,065	36,314
2031	10,945	7,472	50,034	36,667
2032	11,209	7,531	51,070	37,109
2033	11,479	7,580	51,978	37,344
2034	11,736	7,636	52,911	37,692
2035	11,996	7,696	53,825	38,129
2036	12,256	7,747	54,742	38,434
2037	12,517	7,797	55,666	38,802
2038	12,770	7,843	56,541	39,260
2039	13,026	7,887	57,424	39,588
2040	13,282	7,928	58,315	39,981
2041	13,540	7,966	59,214	40,457
2042	13,797	8,000	60,103	40,801
2043	14,055	8,032	60,996	41,207
2044	14,314	8,060	61,892	41,692
2045	14,574	8,085	62,793	41,851
2046	14,835	8,107	63,697	42,154
2047		8,118		42,537
2048		8,125		42,781
2049		8,132		43,086
2050		8,156		43,472

Figure 2.6-12 Energy Sales Forecast Comparison – 2007 ERP & 2011 ERP

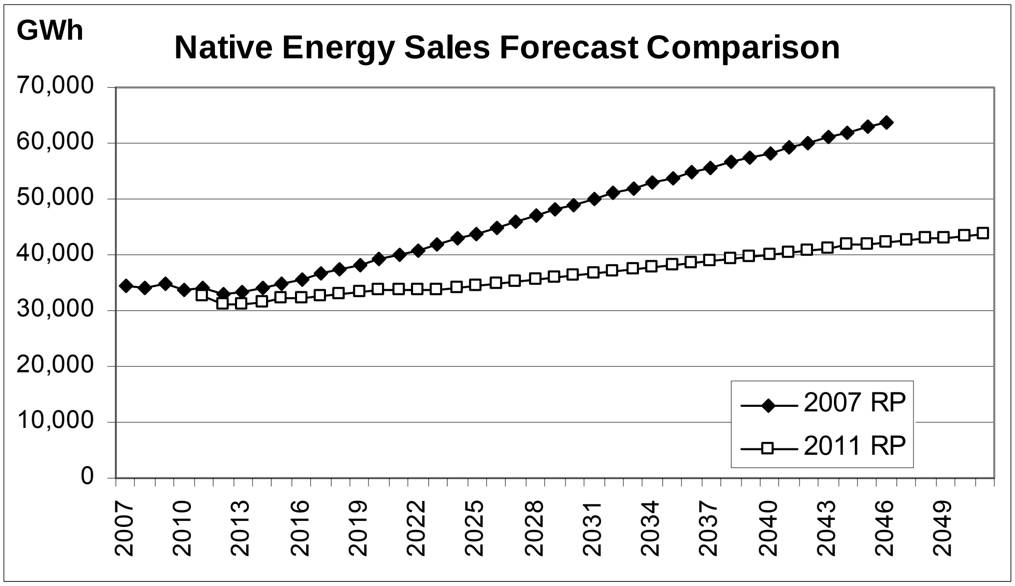
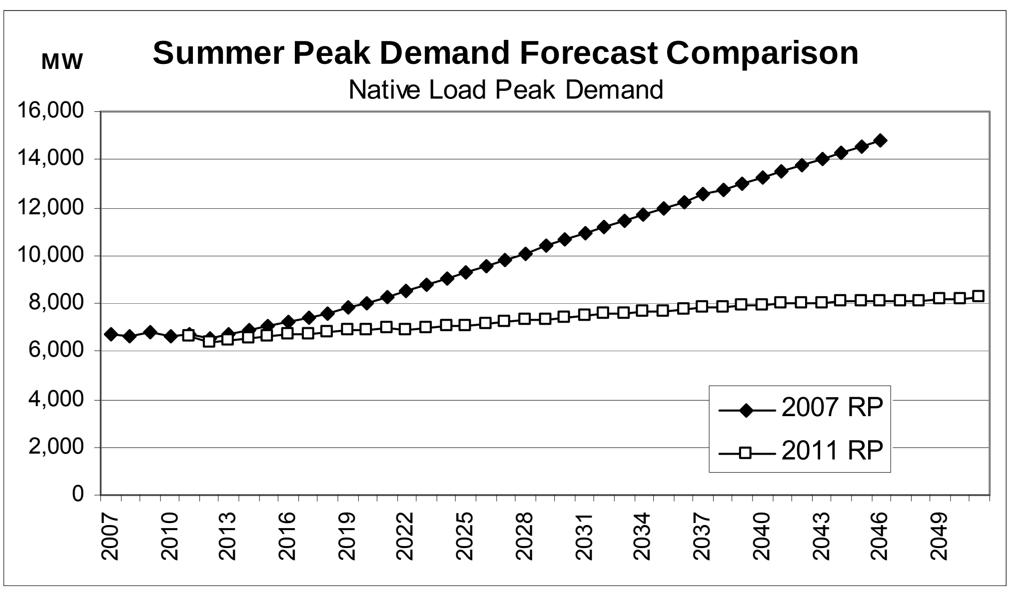


Figure 2.6-13 Summer Native Load Peak Demand Forecast Comparison – 2007 ERP & 2011 ERP



Description and Justification

The following tables show the parameters associated with Public Service's econometric forecasting models.

Table 2.6-25 Number of Residential Electric Customers

REGRESSION PERIOD: Jan 2000- Aug 2008				
NUMBER OF OBSERVATIONS: 139				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
Residential Customers = C1*HousingStock + C2*CRSPh1 + C3*CRSPh2				
ARMA(1,0) process applied to errors				
Variable	**Coefficient**	**Std Err**	**T-Stat**	**P-Value**
C1	529.1724	5.59314	94.61097	0.00%
C2	-4327.16	1705.86	-2.53665	1.23%
C3	-10306.8	1701.823	-6.05631	0.00%
AR(1)	0.982678	0.008489	115.7567	0.00%

Table 2.6-26 Residential Electric Customers – Regression Statistics

Regression Statistics	
Iterations	8
Adjusted Observations	167
Deg. of Freedom for Error	150
R-Squared	0.999
Adjusted R-Squared	0.999
Durbin-Watson Statistic	1.787
Durbin-H Statistic	#NA
AIC	15.509
BIC	15.827
F-Statistic	12406.488
Prob (F-Statistic)	0
Log-Likelihood	-1505.92
Model Sum of Squares	1042156785529
Sum of Squared Errors	741184842
Mean Squared Error	4941232.28
Std. Error of Regression	2222.89
Mean Abs. Dev. (MAD)	1435.27
Mean Abs. % Err. (MAPE)	0.15%
Ljung-Box Statistic	33.09
Prob (Ljung-Box)	0.1022
Frequency of historical data is monthly	

Table 2.6-27 Residential Electric Customers – Definitions and Sources

Variable Name	Definition/Source
Residential Customers	PSCo residential electric customers / PSCo
Housing Stock	Colorado housing Stock / IHS Global Insight Inc.
CRSPh1	Binary variable for the timing of CRS Phase 1
CRSPh2	Binary variable for the timing of CRS Phase 2

Table 2.6-28 Residential Electric Sales per Customer

SAMPLE PERIOD: Jan 2000 through Aug 2011				
NUMBER OF OBSERVATIONS: 139				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
AvgRes_Use = C1*Cooling + C2*Heating +C3*Base +				
C4*Feb + C5*Mar + C76*Apr + C7*May +				
C8*Jun + C9*Sep +C10*Oct + C11*Nov +				
C12*Dec				
ARMA(1,0) process applied to errors				
Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
C1	0.0817819	0.0050523	16.187194	0.00%
C2	0.017559	0.0014181	12.382412	0.00%
C3	263.32161	4.8022056	54.833472	0.00%
C4	-95.293381	5.7340423	-16.618884	0.00%
C5	-86.005504	6.5621935	-13.106213	0.00%
C6	-101.53146	7.3363181	-13.839566	0.00%
C7	-91.07391	7.9248234	-11.492232	0.00%
C8	-51.789528	7.4049738	-6.993884	0.00%
C9	-27.896539	6.9277997	-4.0267531	0.01%
C10	-99.658655	9.1569547	-10.883384	0.00%
C11	-124.89327	8.4652169	-14.7537	0.00%
C12	-43.288552	5.989392	-7.227537	0.00%
AR(1)	0.3882961	0.0825073	4.7062037	0.00%

Table 2.6-29 Residential Electric Sales per Customer – Regression Statistics

Regression Statistics	
Iterations	8
Adjusted Observations	139
Deg. of Freedom for Error	126
R-Squared	0.963
Adjusted R-Squared	0.959
Durbin-Watson Statistic	2.002
Durbin-H Statistic	#NA
AIC	5.734
BIC	6.008
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-582.71
Model Sum of Squares	921,226.29
Sum of Squared Errors	35,630.68
Mean Squared Error	282.78
Std. Error of Regression	16.82
Mean Abs. Dev. (MAD)	12.34
Mean Abs. % Err. (MAPE)	1.93%
Ljung-Box Statistic	23.69
Prob (Ljung-Box)	0.4792

Table 2.6-30 Residential Electric Sales per Customer – Definition and Sources

Variable Name	Definition/Source
AvgRes_Use	Residential kWh sales per customer/PSCo
Cooling	CoolIndex * CoolUse CoolUse = (Price^(-0.2))*(Income per Household^0.2)*(Household Size^0.01)*Cooling Degree Days/ PSCo, IHS Global Insight Inc.
Heating	HeatIndex * HeatUse HeatUse = (Price^(-0.2))*(Income per Household^0.2)*(Household Size^0.01)*Heating Degree Days/ PSCo, IHS Global Insight Inc.
Base	BaseIndex*BaseUse BaseUse = (Price^(-0.2))*(Income per Household^0.2)*(Household Size^0.01)*(Hours of Light^(-0.2))/ PSCo, IHS Global Insight Inc.
Feb-Dec	Binary variables for each month except January, July, and August

Table 2.6-31 Commercial / Industrial Electric Sales

SAMPLE PERIOD: Jan 1999 through Aug 2011				
NUMBER OF OBSERVATIONS: 151				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
GS_MWh = C1*GS_Cool + C2*GS_Base + C3*BillCycleDays + C4*Jan + C5*Feb + C6*Mar + C7*Apr + C8*May + C9*Jun + C10*Jul + C11*Aug + C12*Sep + C13*Oct + C14*Nov + C15*Dec + C16*Jul04 + C17*Aug04 + C18*Jan07 + C19*CRSPh2 + C20 WS_Add_MW				
ARMA(1,0) process applied to errors				
Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
C1	12.99643	3.48322	3.731154	0.03%
C2	3185.154	271.1244	11.74794	0.00%
C3	27956.5	2998.857	9.322384	0.00%
C4	-500477	138099.6	-3.62403	0.04%
C5	-542857	129760.7	-4.18352	0.01%
C6	-487356	130641.4	-3.73049	0.03%
C7	-517893	127429	-4.06417	0.01%
C8	-489317	126943.6	-3.8546	0.02%
C9	-454200	129003.8	-3.52083	0.06%
C10	-388588	126030.7	-3.08328	0.25%
C11	-370436	128281.8	-2.88767	0.45%
C12	-407096	127481.1	-3.19338	0.18%
C13	-499682	130565.4	-3.82706	0.02%
C14	-541743	129226.9	-4.19218	0.01%
C15	-536152	135922.7	-3.94454	0.01%
C16	-322260	42783.41	-7.53235	0.00%
C17	206886.5	45298.82	4.567151	0.00%
C18	106886.2	39797.74	2.685735	0.82%
C19	29817.49	7620.563	3.912767	0.02%
C20	1098.936	134.5027	8.17036	0.00%
AR(1)	-0.34038	0.082368	-4.13238	0.01%

Table 2.6-32 Commercial/Industrial Electric Sales – Regression Statistics

Regression Statistics	
Iterations	15
Adjusted Observations	151
Deg. of Freedom for Error	130
R-Squared	0.924104575
Adjusted R-Squared	0.912428356
Durbin-Watson Statistic	1.902702502
Durbin-H Statistic	#NA
AIC	21.31621546
BIC	21.73583716
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1802.633986
Model Sum of Squares	2.51884E+12
Sum of Squared Errors	2.06869E+11
Mean Squared Error	1591296851
Std. Error of Regression	39891.0623
Mean Abs. Dev. (MAD)	27618.41571
Mean Abs. % Err. (MAPE)	1.87%
Ljung-Box Statistic	34.10872992
Prob (Ljung-Box)	0.082755148
Frequency of historical data is monthly	

Table 2.6-33 Commercial & Industrial Electric Sales – Definitions and Sources

Variable Name	Definition/Source
GS_MWh	Commercial/Industrial electric sales/PSCo
GS_Cool	Commercial Cooling Index * (Price^(-0.2)) * (United States Gross Domestic Product^0.3) * Cooling Degree Days (base 65)/Itron, Inc., PSCo, IHS Global Insight Inc., the National Weather Service, Denver, Colorado.
GS_Base	"Other" Commercial Index * (Price^(-0.2)) * (united States Gross Domestic Product^0.6) * (Hours of Light^(-0.2))/Itron, Inc., PSCo, IHS Global Insight Inc.
BillCycleDays	Average number of days in the monthly billing period
Jan-Dec	Binary variables for each month
Jul04	Binary variable = 0 for all months except July 2004 = 1
Aug04	Binary variable = 0 for all months except August 2004 = 1
Jan07	Binary variable = 0 for all months except January 2007 = 1
CRSPh2	Binary variable for the timing of CRS Phase 2
WS_Add_MW	New load additions from large industry expansion

Table 2.6-34 Electric Sales to Other Public Authorities

SAMPLE PERIOD: Jan 2000 through Aug 2011				
NUMBER OF OBSERVATIONS: 140				
LINEAR LEAST SQUARES MODEL				
Public Authority = C1 + C2*GS_Base + C3*LightRail2 + C4*LightRail3				
Variable	**Coefficient**	**Std Err**	**T-Stat**	**P-Value**
C1	-2821.95	738.8074	-3.8196	0.02%
C2	10.46715	2.270009	4.611062	0.00%
C3	1015.765	76.08405	13.35057	0.00%
C4	2068.463	67.49655	30.64547	0.00%

Table 2.6-35 Electric Sales to Other Public Authorities – Regression Statistics

Regression Statistics	
Iterations	1
Adjusted Observations	140
Deg. of Freedom for Error	136
R-Squared	0.945708892
Adjusted R-Squared	0.944511295
Durbin-Watson Statistic	2.115807474
Durbin-H Statistic	#NA
AIC	11.6201241
BIC	11.70417103
F-Statistic	789.6714289
Prob (F-Statistic)	0
Log-Likelihood	-1008.060082
Model Sum of Squares	256386856
Sum of Squared Errors	14718616.35
Mean Squared Error	108225.1202
Std. Error of Regression	328.9758657
Mean Abs. Dev. (MAD)	198.757732
Mean Abs. % Err. (MAPE)	11.53%
Ljung-Box Statistic	19.86871829
Prob (Ljung-Box)	0.704216863
Frequency of historical data is monthly	

Table 2.6-36 Electric Sales to Other Public Authorities – Definitions and Sources

Variable Name	Definition/Source
Public Authority	Public Authority electric sales /PSCo
GS_Base	"Other" Commercial Index * (Price^(-0.2)) * (US Gross Domestic Product^0.6) * (Hours of Light^(-0.2))/Itron, Inc., PSCo, IHS Global Insight Inc.
Jan-Dec	Binary variables for each month
LightRail1	Binary variable = 0 for all months until December 2001, = 1 after
LightRail2	Binary variable = 0 for all months until October 2002, = 1 after
Nov02	Binary variable = 0 for all months except Nov 2002 = 1
Oct02	Binary variable = 0 for all months except Oct 2002 = 1

Table 2.6-37 Electric Street and Highway Lighting Sales

REGRESSION PERIOD: Jan 2000 - Aug 2011				
NUMBER OF OBSERVATIONS: 139				
LINEAR LEAST SQUARES MODEL WITH ARMA ERRORS				
StreetLight = C1*ResCustomers + C2*Jan + C3*Feb + C4*Mar + C5*Apr + C6*May + C7*Jun + C8*Aug + C9*Sep + C10*Oct + C11*Nov + C12*Dec + C13* CRSP2(-2 lag)				
ARMA(1,0) process applied to errors				
Variable	**Coefficient**	**Std Err**	**T-Stat**	**P-Value**
C1	0.011444	0.000118	97.02396	0.00%
C2	5999.073	154.8164	38.74959	0.00%
C3	5476.825	151.7882	36.08202	0.00%
C4	3456.241	150.8081	22.91814	0.00%
C5	3370.914	148.8591	22.645	0.00%
C6	1541.183	142.9782	10.77915	0.00%
C7	436.2523	123.8809	3.521546	0.06%
C8	604.1084	123.3676	4.896816	0.00%
C9	1459.953	145.677	10.02185	0.00%
C10	2281.415	151.8473	15.02441	0.00%
C11	3885.338	153.8185	25.25924	0.00%
C12	4729.52	154.5317	30.60549	0.00%
C13	-978.638	96.52836	-10.1383	0.00%
AR(1)	0.335357	0.08181	4.099215	0.01%

Table 2.6-38 Electric Street and Highway Lighting Sales – Regression Statistics

Regression Statistics	
Iterations	8
Adjusted Observations	139
Deg. of Freedom for Error	125
R-Squared	0.972262897
Adjusted R-Squared	0.969378239
Durbin-Watson Statistic	2.207686307
Durbin-H Statistic	#NA
AIC	11.81425877
BIC	12.1098173
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1004.323441
Model Sum of Squares	538419808.3
Sum of Squared Errors	15360254.52
Mean Squared Error	122882.0361
Std. Error of Regression	350.545341
Mean Abs. Dev. (MAD)	226.0856831
Mean Abs. % Err. (MAPE)	1.57%
Ljung-Box Statistic	51.57466992
Prob (Ljung-Box)	0.000888671
Frequency of historical data is monthly	

Table 2.6-39 Electric Street and Highway Lighting Sales – Definitions and Sources

Variable Name	Definition/Source
StreetLight	PSCo street and highway lighting electric sales/ PSCo
ResCustomers	Historical and forecasted residential customers/PSCo
Jan-Dec	Binary variables for each month except July
CRSPh2(-2 lag)	Binary variable for the timing of CRS Phase 2 lagged 2 periods

Table 2.6-40 Residential Contribution to System Peak Demand

SAMPLE PERIOD: Jan 2002 through Jun 2011				
NUMBER OF OBSERVATIONS: 114				
LINEAR LEAST SQUARES MODEL				
Res_Coincident = C1*Res_SalesTrend + C2*ResCoolTrend_CDD_Cust_Jun + C3*ResCoolTrend_CDD_Cust_Jul + C5*ResCoolTrend_CDD_Cust_Aug + C8*Oct_HDD + C9*Nov_HDD + C10*Dec_HDD + C11*Jan_HDD + C12*Feb_HDD + C13*Mar_HDD + C14*Sep08 + C15*Oct10 + C16*Oct05 + C17*Apr06 + C18*Apr07 + C19*May07 + C20*Oct07				
Variable	**Coefficient**	**Std Err**	**T-Stat**	**P-Value**
C1	1.995	0.031	65.15862	0.00%
C2	0.000	0.000	10.60367	0.00%
C3	0.000	0.000	14.85067	0.00%
C4	0.000	0.000	11.5454	0.00%
C5	0.000	0.000	2.48797	1.45%
C6	0.000	0.000	5.137378	0.00%
C7	0.000	0.000	11.14755	0.00%
C8	0.000	0.000	9.591563	0.00%
C9	0.000	0.000	8.217774	0.00%
C10	0.000	0.000	3.868412	0.02%
C11	651.548	123.197	5.288659	0.00%
C12	-570.748	123.286	-4.62945	0.00%
C13	-417.834	122.745	-3.40409	0.10%
C14	-540.877	122.957	-4.39891	0.00%
C15	-527.310	123.124	-4.28275	0.00%
C16	-431.558	123.142	-3.50457	0.07%
C17	-453.122	123.226	-3.67716	0.04%

Table 2.6-41 Residential Contribution to System Peak Demand – Regression Statistics

Regression Statistics	
Iterations	1
Adjusted Observations	114
Deg. of Freedom for Error	97
R-Squared	0.873674566
Adjusted R-Squared	0.852837381
Durbin-Watson Statistic	1.903430898
Durbin-H Statistic	#NA
AIC	9.729341436
BIC	10.13737103
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-699.3314547
Model Sum of Squares	9831881.158
Sum of Squared Errors	1421601.016
Mean Squared Error	14655.68058
Std. Error of Regression	121.0606483
Mean Abs. Dev. (MAD)	81.69048107
Mean Abs. % Err. (MAPE)	4.98%
Ljung-Box Statistic	29.92158688
Prob (Ljung-Box)	0.1873643
Frequency of historical data is monthly	

Table 2.6-42 Residential Contribution to System Peak Demand – Definition and Sources

Variable Name	Definition/Source
Res_Coincident	Residential class contribution to system peak, MW/PSCo
Res_SalesTrend	12 month moving average of actual and forecast Residential kWh sales/ PSCo (calculated internally in the energy sales model)
ResCoolTrend_ CDD_Cust	Cooling Degree Days (base 65) * Residential Cooling Index*Customer Counts for the months of June, July, and August/ the National Weather Service, Denver, Colorado, PSCo
HDD	Heating Degree Days (base 55) for months October-March/ calculated from data from the National Weather Service, Denver, Colorado
Jan – Nov	Binary variables for each month except December
Oct97	Binary variable = 0 for all months except October 1997 = 1
Jan97	Binary variable = 0 for all months except January 1997 = 1
Oct01	Binary variable = 0 for all months except October 2001 = 1
May01	Binary variable = 0 for all months except May 2001 = 1
Aug02	Binary variable = 0 for all months except August 2002 = 1
Sep02	Binary variable = 0 for all months except September 2002 = 1
Oct05	Binary variable = 0 for all months except October 2005 = 1

Table 2.6-43 Non-residential Contribution to System Peak Demand

SAMPLE PERIOD: Jan 1999 through Jun 2011				
NUMBER OF OBSERVATIONS: 150				
LINEAR LEAST SQUARES MODEL				
NonRes_Coincident = C1*NonRes_SalesTrend + C2*May_PDMaxTemp_Cust + C3*Jun_PDMaxTemp_Cust+ C4*Jul_PDAvgTemp_Cust + C5*Aug_PDAvgTemp_Cust + C6*Sep_PDMaxTemp_Cust + C7*Oct_PDMaxTemp_Cust + C8*Employment + C9*Sep08				
Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
C1	0.576904	0.237262	2.431506	1.63%
C2	4.86E-05	4.15E-06	11.72261	0.00%
C3	5.95E-05	3.81E-06	15.59859	0.00%
C4	8.7E-05	4.62E-06	18.83268	0.00%
C5	8.4E-05	4.71E-06	17.85602	0.00%
C6	5.89E-05	4.38E-06	13.45913	0.00%
C7	2.14E-05	6.17E-06	3.462804	0.07%
C8	0.695048	0.159757	4.35065	0.00%
C9	-999.869	180.3615	-5.5437	0.00%

Table 2.6-44 Non-residential Contribution to System Peak Demand – Regression Statistics

Regression Statistics	
Iterations	1
Adjusted Observations	150
Deg. of Freedom for Error	141
R-Squared	0.863000004
Adjusted R-Squared	0.855226954
Durbin-Watson Statistic	1.58137326
Durbin-H Statistic	#NA
AIC	10.35297453
BIC	10.53361264
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-980.3138694
Model Sum of Squares	26272770.47
Sum of Squared Errors	4170764.122
Mean Squared Error	29579.88739
Std. Error of Regression	171.9880443
Mean Abs. Dev. (MAD)	128.1598431
Mean Abs. % Err. (MAPE)	4.82%
Ljung-Box Statistic	28.14346843
Prob (Ljung-Box)	0.254035076
Frequency of historical data is monthly	

Table 2.6-45 Non-residential Contribution to System Peak Demand – Definitions and Sources

Variable Name	Definition/Source
NonRes_Coincident	Commercial and industrial class contribution to system peak, MW/ PSCo
NonRes_SalesTrend	12 month moving average of actual and forecast Non-Residential kWh sales/ PSCo (calculated internally in the energy sales model)
PDMaxTemp_Cust	Peak day maximum temperature*Commercial-Industrial Customers for months May, June, September, and October/ the National Weather Service, Denver, Colorado, PSCo
PDAvgTemp_Cust	Peak day average temperature*Commercial-Industrial Customers for months July and August/ the National Weather Service, Denver, Colorado, PSCo
Employment	Colorado non-farm employment /IHS Global Insight Inc.
Sep08	Binary variable = 0 for all months except September 2008 = 1

Coordination Letters

Please see Attachment 2.6-1 for copies of the coordination letters exchanged with other electric utilities.

Attachment 2.6-1 Coordination Letters

Letter to Black Hills Colorado

June 10, 2011

Mr. Chris Kilpatrick
Director Resource Planning and Electric Rates
Black Hills Corporation
625 Ninth Street
P.O. Box 1400
Rapid City, South Dakota 57709-1400

Subject: Public Service Company of Colorado's 2011 Electric Resource Plan

Dear Mr. Kilpatrick,
The Colorado Public Utilities Commission's Resource Planning Rules require utilities to coordinate the reporting of purchases and sales for purposes of resource planning between the utilities. With this letter, Public Service requests that Black Hills Colorado confirm that the transaction information listed below is consistent with that which Black Hills Colorado plans to use in any resource plan filing or reporting.

Specifically, our request relates to CPUC Rule 3607(b), which states:
Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

The capacity below reflects the amount of power that Public Service supplies Black Hills Colorado. The listed capacity is included in our resource planning and modeling assumptions. The listed capacity is subject to all of the terms and conditions of the contract. This letter is not intended to limit Public Service or Black Hills Colorado in any manner regarding future administration of the contract.

Year	Capacity (MW)
2011	300

If you agree with this contract information, please reply with a letter of acknowledgement. We anticipate that we will include your reply letter, as well as this letter of request, in our plan filing to demonstrate compliance.

Thank you in advance for reviewing this information. Please contact me at (303) 571-2749 with any questions.

Sincerely,

Jim Hill
Director Resource Planning and Bidding
1800 Larimer Street
Suite 1400
Denver, CO 80202

<u>Letter to Tri-State</u>

June 10, 2011

Mr. Rob Wolaver
Senior Manager of Energy Resources
Tri-State Generation & Transmission
P.O. Box 33695
Denver, CO 80233

Subject: Public Service Company of Colorado's 2011 Electric Resource Plan

Dear Rob,
The Colorado Public Utilities Commission's Resource Planning Rules require utilities to coordinate the reporting of purchases and sales for purposes of resource planning between the utilities. With this letter, Public Service requests that Tri-State confirm that the transaction information listed below is consistent with that which Tri-State plans to use in any resource plan filing or reporting.

Specifically, our request relates to CPUC Rule 3607(b), which states:
Utilities required to comply with these rules shall coordinate their plan filings such that the amount of electricity purchases and sales between utilities during the planning period is reflected uniformly in their respective plans. Disputes regarding the amount, timing, price, or other terms and conditions of such purchases and sales shall be fully explained in each utility's plan. If a utility files an interim plan as specified in rule 3603, the utility is not required to coordinate that filing with other utilities.

The capacities shown in the following table reflect the amount of power that Public Service purchases from Tri-State to help meet our firm load obligation. The listed capacities are included in our resource planning and modeling assumptions. The listed capacities are subject to all of the terms and conditions of each of the individual contracts. This letter is not intended to limit Public Service or Tri-State in any manner regarding future administration of these or other contracts.

	Contract	**Summer**	**Contract**	
Contract	**Source**	**Capacity (MW)**	**Start**	**Expiration**
Brighton Restructure	Brighton CTs	132	5/1/2013	4/30/2016
Limon Restructure	Limon CT	66	5/1/2013	4/30/2016
TSGT #2	LRS, Craig	100	4/1/1987	3/31/2017
TSGT #3	LRS, Craig	25	4/1/1992	3/31/2016
TSGT #5	LRS, Craig, Nucla	100	4/15/1992	12/31/2011

If you agree with this contract information, please reply with a letter of acknowledgement. We anticipate that we will include your reply letter, as well as this letter of request, in our plan filing to demonstrate compliance.

Thank you in advance for reviewing this information. Please contact me at (303) 571-2749 with any questions.

Sincerely,

Jim Hill
Director Resource Planning and Bidding
1800 Larimer Street
Suite 1400
Denver, CO 80202

<u>Reply from Black Hills</u>

Black Hills Energy

Wendy M. Moser
Senior Corporate Counsel
Wendy.Moserl@blackhillscorp.com

1515 Wynkoop, Suite 500
Denver, CO 80202
P: 303-566-3405
F: 303-476-5980

October 5, 2011

Jim Hill
Director Resource Planning and Bidding
Xcel Energy

1800 Larimer Street
Suite 1400
Denver, CO 80202

Re: Public Service Company of Colorado's 2011 Electric Resource Plan

Dear Mr. Hill:

Your letter of September 21, 2011 to Chris Kilpatrick has been referred to me for response. Your letter requests, pursuant to the Commission resource planning rules, confirmation of the amount of power capacity that Public Service will supply to Black Hills/Colorado Electric Utility Company, LP ("Black Hills Energy") under a purchase power agreement. The power capacity amount, stated in your letter, that Public Service will supply Black Hills Energy under a purchase power agreement through December 2011, follows:

Year	Capacity (MW)
2011	300
2012	0

Black Hills agrees that the stated capacity amount is the capacity amount that Public Service will deliver to Black Hills Energy through December 2011 under the agreement, and is consistent with that which Black Hills Energy plans to use in any resource plan filing or reporting.

This acknowledgement is being provided pursuant to Commission Rule 3607(b) which requires coordination among utilities so that the capacity amount is reflected uniformly in utilities' respective resource plan filings.

Sincerely,

Wendy M. Moser

cc: Todd Brink
Eric Scherr

Reply from Tri-State

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.

1100 W. 116TH AVENUE, P.O. BOX 33695, DENVER, COLORADO 80233
303-452-6111

July 26, 2011
Jim Hill
Director Resource Planning and Bidding
Xcel Energy
1800 Larimer Street
Suite 1400
Denver, CO 80202

RE: Public Service Company of Colorado's 2011 Electric Resource Plan

Dear Jim,

Tri-State has reviewed the capacities that Public Service purchases from Tri-State. All of these agree with Tri-State's information with the exception of the Limon and Brighton (Knutson) Turbine contracts. The contracts state that Tri-State will provide at least 64MW of capacity per turbine; 64MW for Limon and 128MW for Brighton. For planning purposes, we assume 68MW per turbine of summer capacity based on the recommendations of Tri-State's generation engineering department. For purposes of resource planning Public Service should use the listed capacities below.

Contract	Contract Source	Summer Capacity (MW)	Contract Start	Contract Expiration
Brighton (Knutson)	Knutson CTs	**136**	5/1/2013	4/30/2016
Limon	Limon CTs	**68**	5/1/2013	4/30/2016
TSGT #2	LRS, Craig	100	4/1/1987	3/31/2017
TSGT #3	LRS, Craig	25	4/1/1992	3/31/2016
TSGT #5	LRS, Craig, Nucla	100	4/15/1992	12/31/2011

If you have any questions or comments, please contact me at kcox@tristategt.org.

Sincerely,

Kevin T. Cox, P.E.
Resource Planning and Analytics Manager

2.7 HOURLY LOAD PROFILES

Introduction

This section contains typical day load patterns on a system-wide basis for each major customer class (by voltage level) provided for peak day, average day and representative off-peak days for each calendar month.

The following monthly class load shapes are developed from Company load research data for the year 2010. The following statistics were used for each requirement:

REQUIREMENT	STATISTIC
Peak Day	System Peak Day
Average Day	Average Weekday Excluding Holidays
Representative Off-Peak Day	Average Weekends and Holidays

The residential and commercial and industrial profiles were developed from aggregated load research classes. These profiles were calculated using the population weighted average load of all the rate classes in each group.

The following pages contain "figures" with tables and graphs for each of the load patterns described above.

Residential	Figures 2.7-1 through 2.7-12
Commercial & Industrial (Secondary)	Figures 2.7-13 through 2.7-24
Commercial & Industrial (Primary)	Figures 2.7-25 through 2.7-36
Commercial & Industrial (Transmission)	Figures 2.7-37 through 2.7-48
Wholesale	Figures 2.7-49 through 2.7-60

Please note that the wholesale data provided for two customers who are part owners in Comanche 3 contains their total load (what is served by both Public Service and Comanche 3). Public Service is required to serve their total load in the event that Comanche 3 is not on line. In addition, the WAPA allocations for the wholesale data are not subtracted from the total load provided because hourly WAPA data is not available.

Figure 2.7-1 Residential January

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9080	0.7450	0.8000
2	0.8820	0.7110	0.7460
3	0.8320	0.6840	0.7140
4	0.8260	0.6880	0.7120
5	0.8380	0.7090	0.7150
6	0.8960	0.7820	0.7380
7	1.0010	0.8970	0.7870
8	1.1580	0.9740	0.8910
9	1.1470	0.9710	0.9950
10	1.0830	0.9680	1.0800
11	1.0460	0.9330	1.1040
12	1.0770	0.8950	1.0860
13	1.0780	0.9060	1.1150
14	1.0690	0.8900	1.0890
15	1.0740	0.9080	1.0590
16	1.0880	0.9210	1.0370
17	1.2250	1.0450	1.1200
18	1.4230	1.2940	1.3360
19	1.4340	1.3540	1.3680
20	1.5530	1.3440	1.3510
21	1.4320	1.2780	1.2700
22	1.3840	1.1640	1.1690
23	1.1900	0.9900	0.9990
24	0.9790	0.8320	0.8590

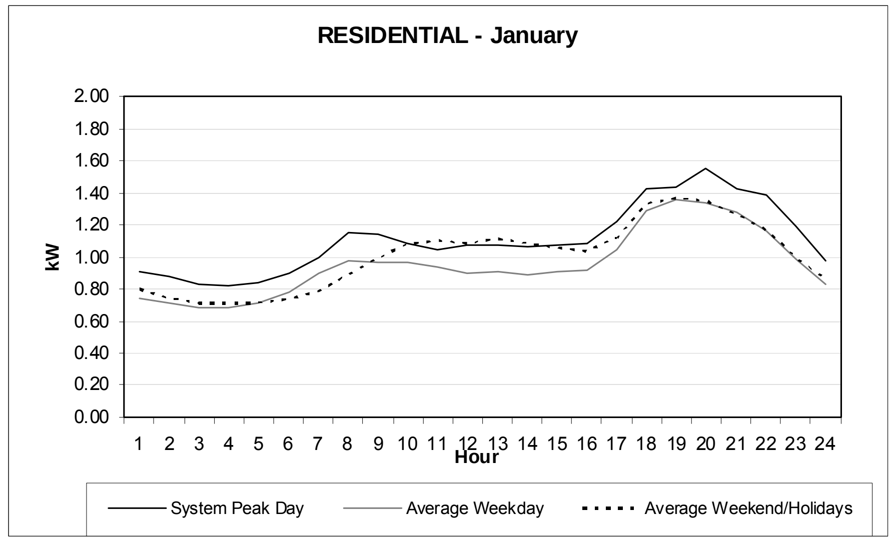


Figure 2.7-2 Residential February

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7780	0.7390	0.7780
2	0.6720	0.6960	0.7100
3	0.6710	0.6880	0.6740
4	0.6750	0.6940	0.6790
5	0.7020	0.7170	0.6800
6	0.7640	0.7910	0.7070
7	0.9110	0.9000	0.7490
8	0.9500	0.9520	0.8990
9	0.9520	0.9550	1.0190
10	0.9210	0.9120	1.0530
11	0.9620	0.8950	1.0540
12	0.8940	0.8640	1.0850
13	1.0030	0.8700	1.1010
14	1.1290	0.8730	1.0990
15	1.0460	0.8640	1.0380
16	1.0500	0.8860	1.0710
17	1.1230	0.9960	1.1360
18	1.3450	1.1810	1.2650
19	1.6140	1.3380	1.2900
20	1.5350	1.2970	1.2680
21	1.4490	1.2690	1.2140
22	1.3550	1.1640	1.1670
23	1.0650	0.9860	0.9890
24	0.8640	0.8310	0.8210

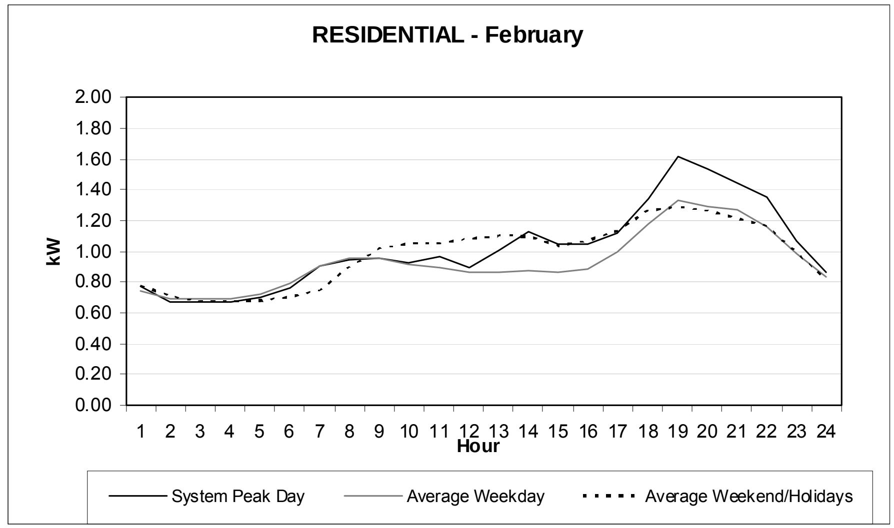


Figure 2.7-3 Residential March

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6860	0.6780	0.7650
2	0.6030	0.6310	0.6990
3	0.6050	0.6140	0.6620
4	0.6000	0.6100	0.6430
5	0.6470	0.6410	0.6660
6	0.7140	0.7160	0.7020
7	0.8440	0.8160	0.7340
8	0.8650	0.8700	0.8370
9	0.8860	0.8680	0.9270
10	0.8980	0.8720	1.0220
11	0.9800	0.8460	1.0320
12	0.8700	0.8020	0.9760
13	0.8850	0.8190	0.9920
14	0.9830	0.7950	0.9680
15	0.9660	0.7820	0.9180
16	0.9600	0.7810	0.9360
17	1.0480	0.8520	0.9540
18	1.2550	1.0110	1.0560
19	1.3450	1.1400	1.1680
20	1.3080	1.1900	1.2320
21	1.3590	1.1990	1.2050
22	1.2410	1.1240	1.1340
23	0.9530	0.9550	0.9830
24	0.7560	0.7890	0.8600

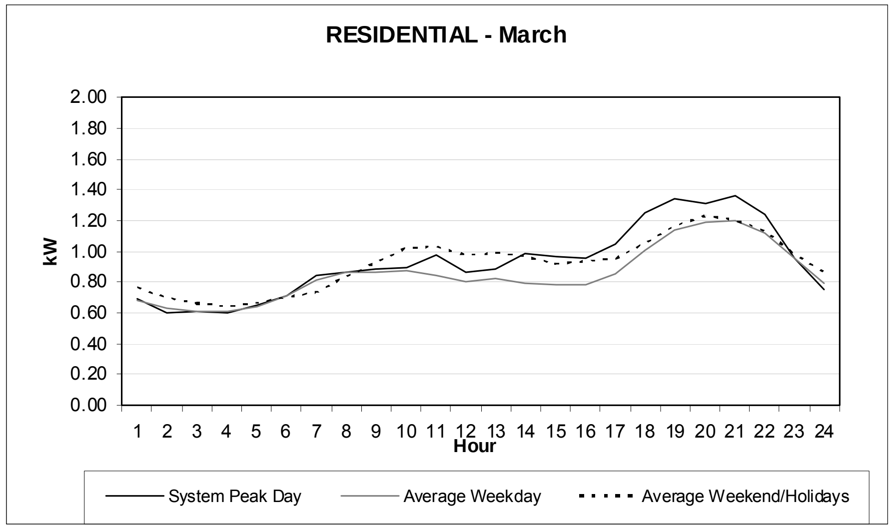


Figure 2.7-4 Residential April

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.5940	0.6470	0.6970
2	0.5440	0.5910	0.6290
3	0.5300	0.5690	0.5940
4	0.5160	0.5610	0.5900
5	0.5360	0.5790	0.6060
6	0.6050	0.6430	0.6290
7	0.7370	0.7480	0.6940
8	0.7900	0.7660	0.7330
9	0.7370	0.7510	0.8430
10	0.7350	0.7420	0.9000
11	0.7810	0.7350	0.8970
12	0.8700	0.7330	0.8880
13	0.9240	0.7340	0.8900
14	0.8310	0.7040	0.8950
15	0.7500	0.6930	0.8130
16	0.7560	0.7100	0.8110
17	0.8640	0.7840	0.8600
18	0.9640	0.8970	0.9300
19	1.1440	0.9720	0.9650
20	1.1850	1.0710	1.0650
21	1.2440	1.0960	1.1090
22	1.1200	1.0360	1.0350
23	0.9560	0.9060	0.9170
24	0.8260	0.7610	0.7860

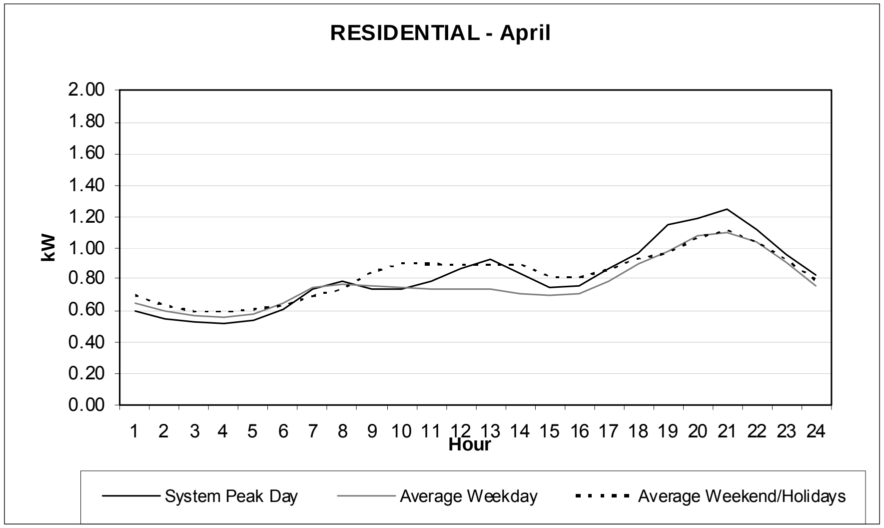


Figure 2.7-5 Residential May

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6770	0.6090	0.6690
2	0.5830	0.5610	0.6080
3	0.5820	0.5320	0.5780
4	0.5260	0.5240	0.5600
5	0.5210	0.5380	0.5640
6	0.5530	0.5990	0.5850
7	0.6390	0.6820	0.6250
8	0.7440	0.7200	0.6840
9	0.7120	0.6970	0.7800
10	0.7000	0.6980	0.8250
11	0.7710	0.6970	0.8330
12	0.7810	0.6670	0.8220
13	0.7600	0.6460	0.8130
14	0.8550	0.6390	0.8220
15	0.9580	0.6470	0.8070
16	0.9960	0.6800	0.7960
17	1.1070	0.7830	0.8270
18	1.2610	0.9010	0.9170
19	1.2340	0.9660	0.9560
20	1.1970	0.9990	0.9680
21	1.1630	1.0360	0.9860
22	1.1750	1.0070	0.9680
23	1.0660	0.8580	0.8680
24	0.9840	0.7180	0.7260

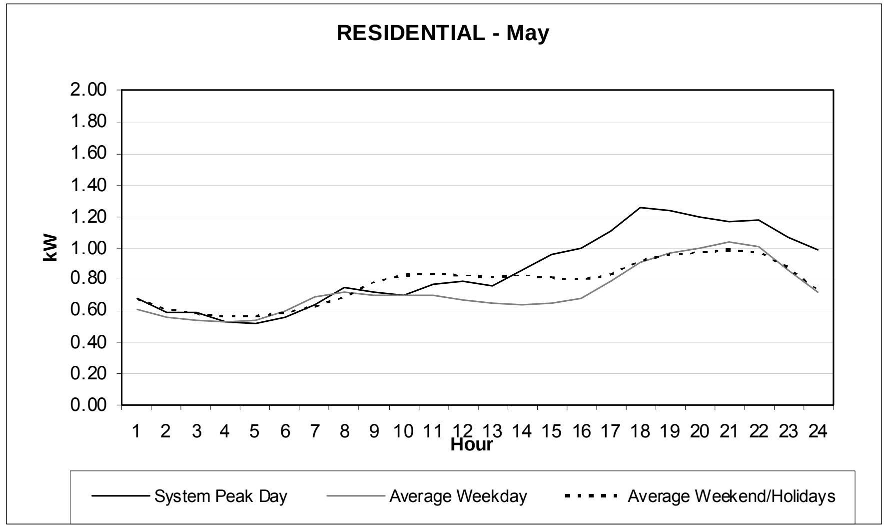


Figure 2.7-6 Residential June

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8930	0.7640	0.7830
2	0.7430	0.6700	0.7110
3	0.6550	0.6200	0.6420
4	0.6130	0.5900	0.6150
5	0.6150	0.5910	0.5900
6	0.6980	0.6330	0.5890
7	0.7490	0.6820	0.6250
8	0.8090	0.7580	0.7190
9	0.9120	0.8370	0.8230
10	0.9230	0.8560	0.9230
11	1.0060	0.9000	0.9770
12	1.0220	0.9070	1.0290
13	1.1740	0.9640	1.0990
14	1.1990	0.9970	1.1290
15	1.2330	1.0650	1.1580
16	1.3510	1.1620	1.1950
17	1.3770	1.2580	1.2330
18	1.5480	1.3670	1.2960
19	1.6090	1.3800	1.2550
20	1.6340	1.3350	1.2010
21	1.6030	1.2960	1.1870
22	1.5970	1.2900	1.1760
23	1.3460	1.1340	1.0570
24	1.0580	0.9390	0.8780

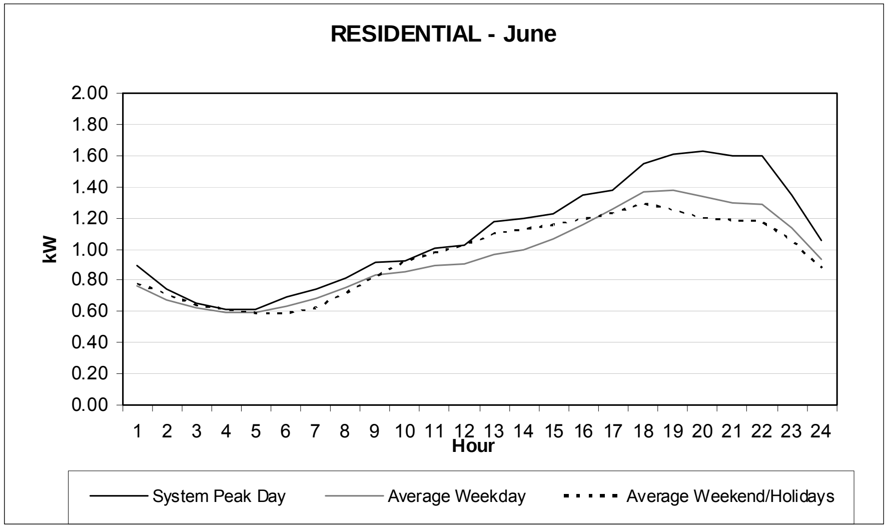


Figure 2.7-7 Residential July

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9660	0.8640	0.9230
2	0.8820	0.7670	0.8130
3	0.7940	0.7040	0.7230
4	0.7240	0.6750	0.6800
5	0.7280	0.6670	0.6590
6	0.7370	0.6880	0.6500
7	0.8120	0.7220	0.6710
8	0.8770	0.8150	0.7490
9	0.9620	0.8750	0.8460
10	1.1340	0.9440	0.9970
11	1.3330	1.0260	1.1160
12	1.3750	1.0940	1.1900
13	1.4530	1.1600	1.3040
14	1.5460	1.2260	1.3740
15	1.5880	1.2860	1.4220
16	1.6690	1.3560	1.4910
17	1.7060	1.4040	1.4990
18	1.7460	1.4860	1.5350
19	1.7830	1.5130	1.4900
20	1.8450	1.4540	1.4110
21	1.6110	1.4290	1.3610
22	1.5330	1.4320	1.3250
23	1.3020	1.2640	1.2110
24	1.0640	1.0630	1.0300

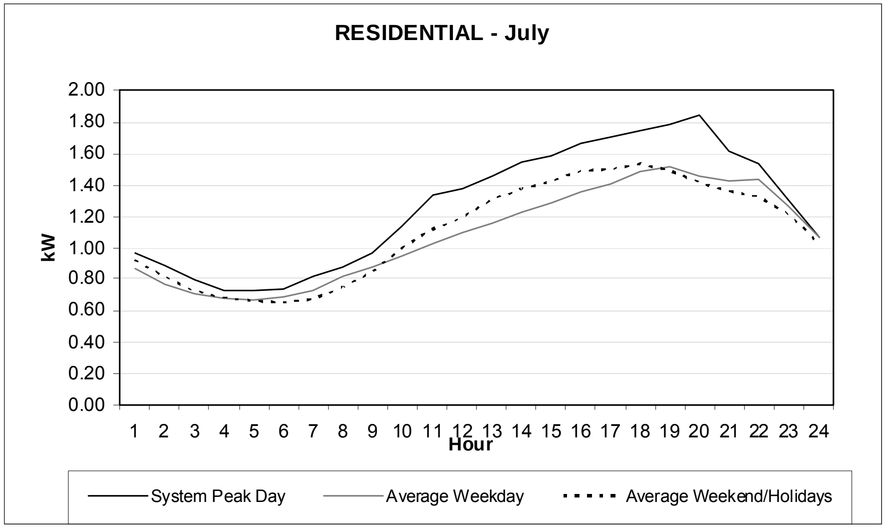


Figure 2.7-8 Residential August

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8020	0.8410	0.8920
2	0.7360	0.7730	0.8100
3	0.6820	0.7190	0.7590
4	0.6700	0.6890	0.7240
5	0.6860	0.6850	0.6970
6	0.7110	0.7160	0.7030
7	0.7460	0.7680	0.7440
8	0.8280	0.8290	0.8230
9	0.8640	0.8550	0.9430
10	0.8790	0.8860	1.0490
11	0.9770	0.9530	1.1270
12	1.0390	1.0010	1.1810
13	1.0600	1.0430	1.2500
14	1.1800	1.0930	1.3180
15	1.2950	1.1460	1.4160
16	1.4750	1.2210	1.4770
17	1.5780	1.2990	1.5400
18	1.7010	1.3810	1.5300
19	1.7780	1.3910	1.4670
20	1.6960	1.3370	1.4230
21	1.7480	1.3730	1.4100
22	1.6090	1.3090	1.3790
23	1.3260	1.1240	1.2290
24	1.1640	0.9450	1.0320

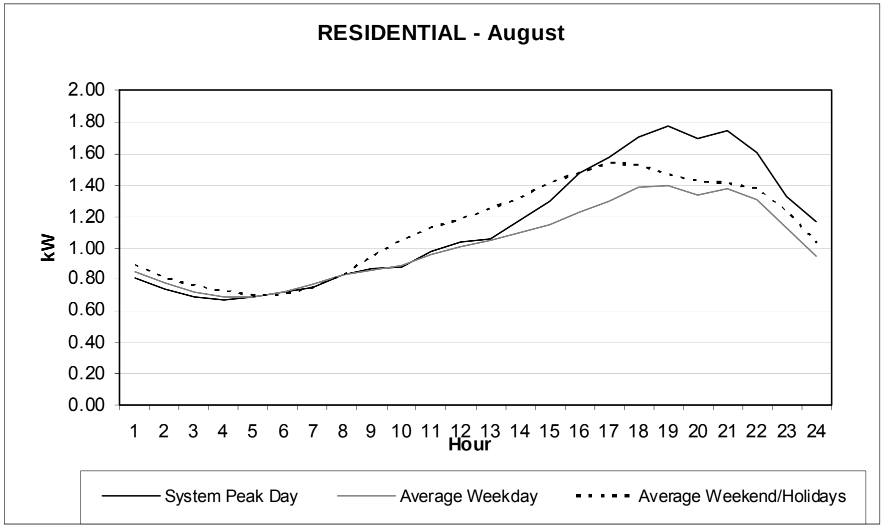


Figure 2.7-9 Residential September

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6740	0.6790	0.7140
2	0.6370	0.6140	0.6530
3	0.5980	0.5780	0.6000
4	0.5600	0.5580	0.5600
5	0.5510	0.5590	0.5500
6	0.5810	0.6030	0.5520
7	0.6940	0.6880	0.6030
8	0.7310	0.7250	0.6960
9	0.6740	0.7060	0.7470
10	0.7020	0.7180	0.8120
11	0.8370	0.7410	0.8500
12	0.8620	0.7590	0.8810
13	0.9340	0.7960	0.9180
14	0.9840	0.8390	0.9850
15	0.9850	0.8610	1.0300
16	1.0880	0.9320	1.0880
17	1.2680	1.0240	1.1450
18	1.3400	1.1190	1.2350
19	1.3850	1.1280	1.2060
20	1.3940	1.1400	1.1800
21	1.3770	1.1710	1.1730
22	1.2570	1.0830	1.0690
23	1.0090	0.9300	0.9320
24	0.8920	0.7900	0.8160

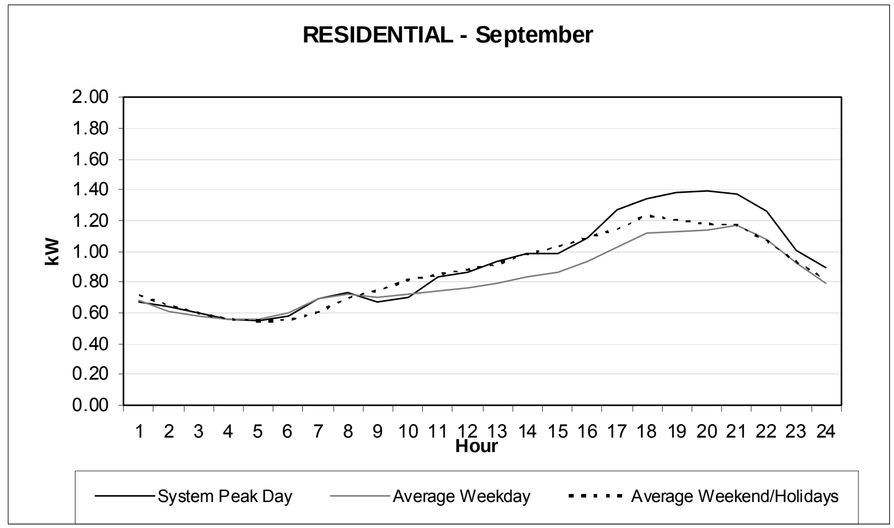


Figure 2.7-10 Residential October

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6090	0.6280	0.6530
2	0.5770	0.5900	0.6060
3	0.5630	0.5660	0.5780
4	0.5360	0.5630	0.5500
5	0.5360	0.5680	0.5520
6	0.6420	0.6360	0.5710
7	0.7000	0.7090	0.5990
8	0.7060	0.7380	0.6540
9	0.6450	0.7370	0.7430
10	0.5880	0.7080	0.7830
11	0.6770	0.7220	0.8070
12	0.6750	0.7030	0.7960
13	0.6460	0.6960	0.8000
14	0.6820	0.7000	0.8030
15	0.6810	0.6900	0.8000
16	0.7580	0.7120	0.8200
17	0.7840	0.7690	0.8740
18	0.8880	0.8870	0.9170
19	0.9930	1.0010	0.9980
20	1.1790	1.0810	1.0720
21	1.2240	1.0450	1.0180
22	1.0900	0.9580	0.9220
23	0.8570	0.8380	0.8100
24	0.7160	0.7190	0.7180

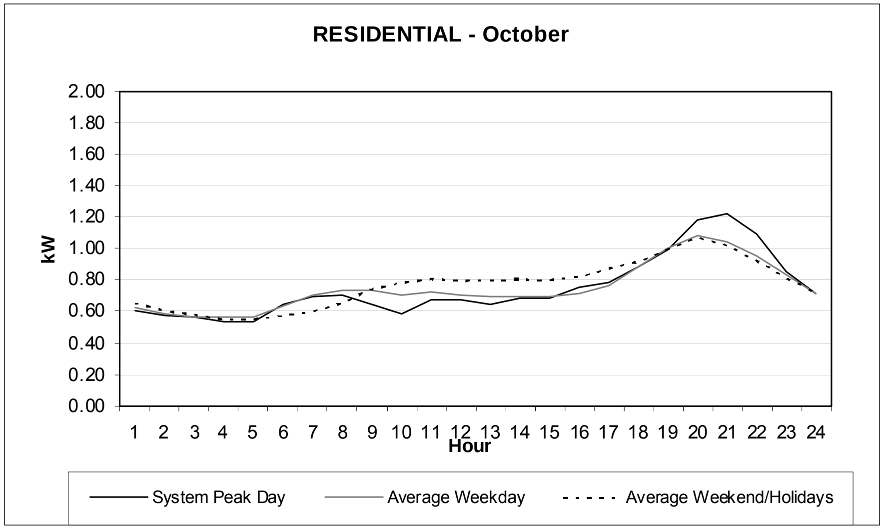


Figure 2.7-11 Residential November

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7510	0.7130	0.7800
2	0.7380	0.6810	0.7250
3	0.6960	0.6660	0.7040
4	0.7220	0.6710	0.7020
5	0.7550	0.6920	0.7060
6	0.7520	0.7090	0.6880
7	0.8400	0.8000	0.7270
8	0.9060	0.8400	0.8340
9	0.9120	0.8460	0.9360
10	0.8580	0.8000	0.9440
11	0.8770	0.7800	0.9610
12	0.8780	0.7670	0.9680
13	0.8740	0.7550	0.9770
14	0.8430	0.7420	0.9380
15	0.8750	0.7480	0.9100
16	0.9500	0.7760	0.9030
17	1.0660	0.8950	1.0310
18	1.3000	1.1210	1.2330
19	1.4510	1.1850	1.2280
20	1.4580	1.1760	1.1630
21	1.3770	1.1460	1.1320
22	1.2520	1.0650	1.0500
23	1.1210	0.9450	0.9250
24	0.9770	0.8160	0.8170

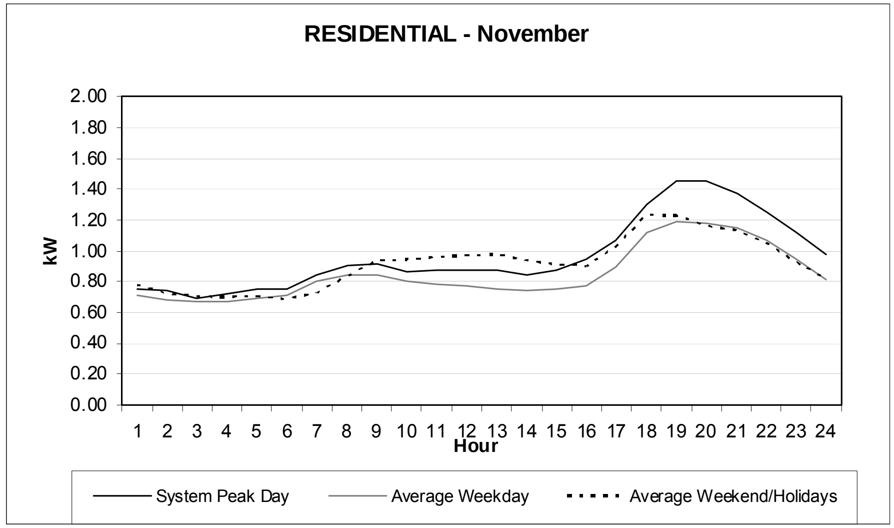


Figure 2.7-12 Residential December

RESIDENTIAL DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0070	0.8040	0.8560
2	0.8840	0.7590	0.8060
3	0.8790	0.7350	0.7800
4	0.9000	0.7380	0.7810
5	0.8620	0.7400	0.7630
6	0.8010	0.7140	0.7100
7	0.8350	0.8140	0.7650
8	0.9070	0.8590	0.8540
9	1.0600	0.8650	0 9620
10	1.1550	0.8240	1 0230
11	1.1340	0.8080	1 0040
12	1.1260	0.7910	1 0090
13	1.1890	0.7880	1 0110
14	1.2300	0.7830	1 0120
15	1.1620	0.7650	0 9910
16	1.1310	0.8060	0 9670
17	1.2200	0.9670	1 0580
18	1.4550	1.2930	1.3620
19	1.5860	1.3380	1.3960
20	1.4020	1.3200	1.3460
21	1.3500	1.2900	1 2880
22	1.3340	1.2220	1 2140
23	1.2560	1.0550	1 0890
24	1.1440	0.9040	0 9540

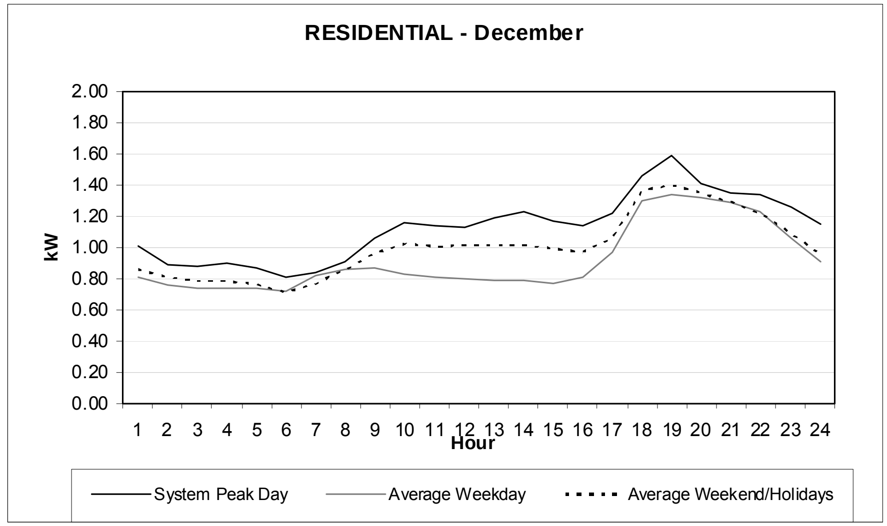


Figure 2.7-13 Commercial & Industrial (Secondary) January

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.8428	8.6257	8.3272
2	9.7017	8.5222	8.1916
3	9.6137	8.5014	8.1278
4	9.7185	8.5739	8.1034
5	9.9018	8.8361	8.1921
6	10 9549	9.9153	8.5042
7	12.3545	11.4221	8.9450
8	13.3979	12.5894	9.0935
9	14 0588	13.3250	9.0786
10	14.4147	13.6061	9.1330
11	14.6649	13.7705	9.2801
12	14.5301	13.6854	9.1928
13	14.4688	13.5752	9.0644
14	14.3097	13.5146	8.9344
15	14.1488	13.3875	8.8336
16	13.7442	12.9581	8.8032
17	13.3167	12.4549	8.8782
18	13.1335	12.0574	9.4306
19	12.3422	11.2078	9.3555
20	11 9136	10.7466	9.1704
21	11.5277	10.2936	9.0085
22	10.8599	9.7467	8.7442
23	10.3298	9.1423	8.4634
24	10 0489	8.8628	8.3188

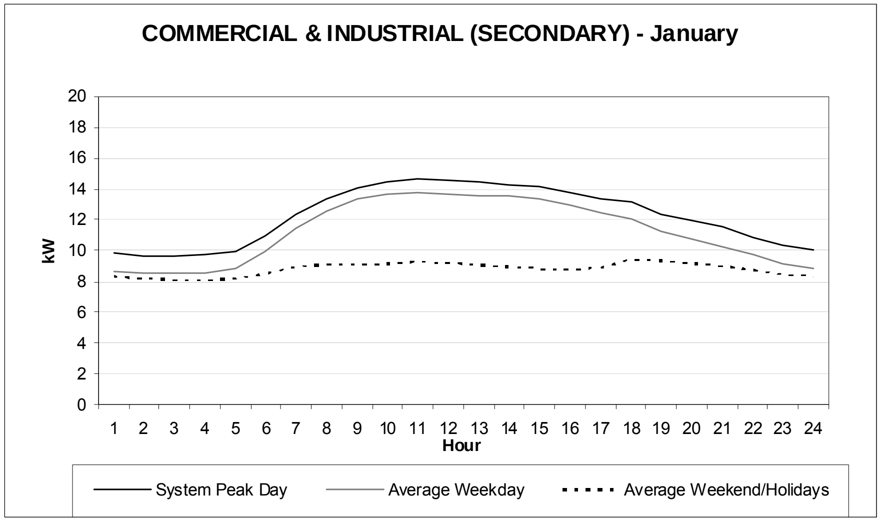


Figure 2.7-14 Commercial & Industrial (Secondary) February

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.1579	8.5184	8.2210
2	8.0799	8.4065	8.0951
3	8.0888	8.3831	7.9914
4	8.2734	8.4410	7.9436
5	8.6493	8.7197	8.0330
6	9.7220	9.7815	8.3280
7	11 2852	11.3265	8.7227
8	12.3000	12.2867	8.8052
9	13.1866	12.9931	9.0512
10	13.6890	13.3441	9.2130
11	13.8500	13.4653	9.3065
12	13.7273	13.3591	9.2656
13	13.7201	13.2789	9.1544
14	13.6817	13.1701	8.9559
15	13.6257	13.0326	8.8522
16	13 2927	12.6021	8.7967
17	12.5528	12.0173	8.8421
18	12 0374	11.4928	9.1375
19	11.4720	10.9849	9.3548
20	10 9719	10.5520	9.2136
21	10.5177	10.0758	9.0799
22	9.9884	9.5512	8.8619
23	9.4273	9.0023	8.5651
24	9.1767	8.7029	8.3826

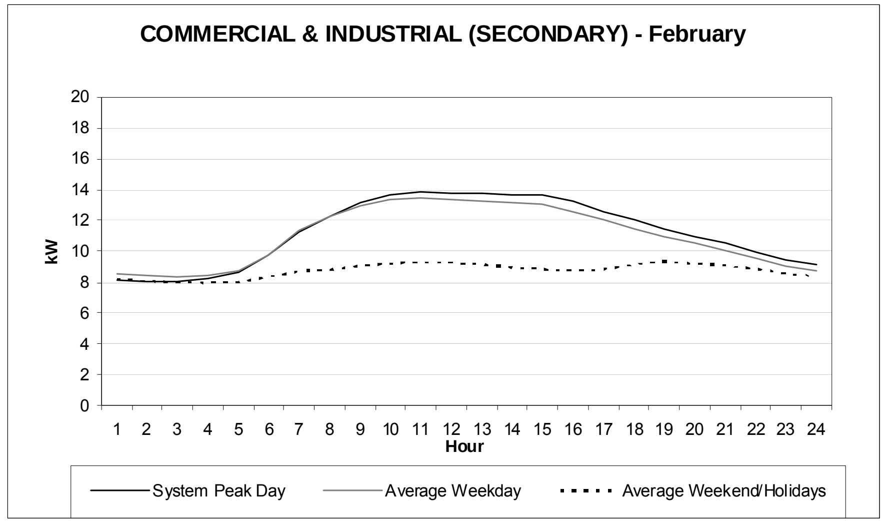


Figure 2.7-15 Commercial & Industrial (Secondary) March

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.5066	8.0021	8.0012
2	7.4726	7.8922	7.8758
3	7.5728	7.8466	7.8315
4	7.5987	7.8944	7.7644
5	7.9867	8.1384	7.8318
6	9.1119	9.1504	8.1015
7	10.5755	10.5694	8.4818
8	11.6777	11.6222	8.5373
9	12.7060	12.4113	8.6933
10	13.1808	12.8126	8.7901
11	13.3960	13.0684	8.9524
12	13.3488	13.0736	8.9676
13	13.3784	13.0190	8.8576
14	13 2781	13.0250	8.6945
15	12 9582	12.9089	8.5896
16	12.5890	12.5412	8.4983
17	12 0016	11.9089	8.3996
18	11.1267	10.9726	8.3782
19	10.6256	10.3087	8.4550
20	10 2321	10.1133	8.5845
21	9.6952	9.6855	8.5596
22	9.2321	9.1668	8.3508
23	8.6626	8.6278	8.0533
24	8.3513	8.3071	7.8543

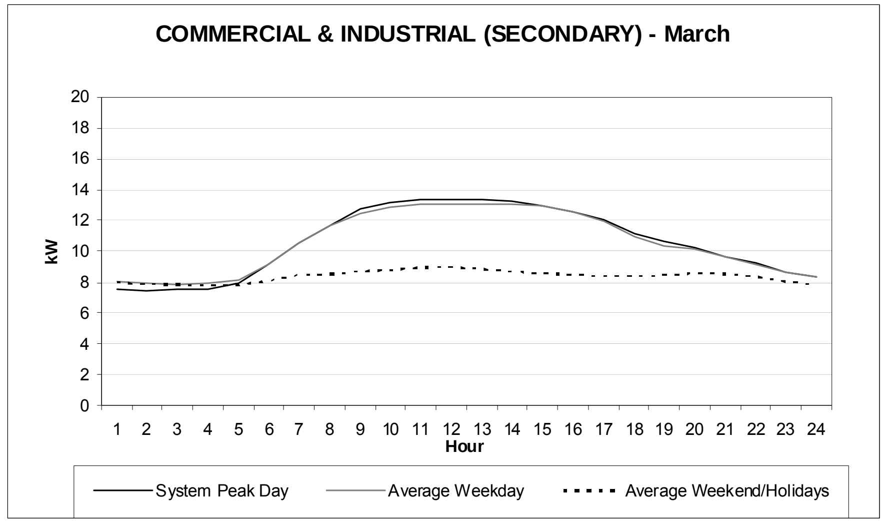


Figure 2.7-16 Commercial & Industrial (Secondary) April

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.6322	7.6657	7.6108
2	7.6303	7.5846	7.4546
3	7.5151	7.4904	7.3766
4	7.5685	7.5256	7.3447
5	7.7596	7.7802	7.4050
6	8.7150	8.7651	7.6154
7	10 2273	10.1367	7.8226
8	11.4537	11.2220	7.9254
9	12.4608	12.1924	8.2036
10	12.8661	12.6604	8.3836
11	13.1008	13.0071	8.6231
12	13.1297	13.1212	8.6868
13	12 9902	13.1357	8.6521
14	13 0281	13.1759	8.4954
15	12 9823	13.0838	8.4217
16	12.3932	12.6223	8.3442
17	11.7598	11.9736	8.2725
18	10.7238	10.9279	8.1533
19	9.8951	9.9360	7.9720
20	9.7793	9.7296	8.0482
21	9.6177	9.5374	8.2270
22	9.0878	8.9789	8.0300
23	8.6079	8.3614	7.7530
24	8.2577	7.9766	7.5522

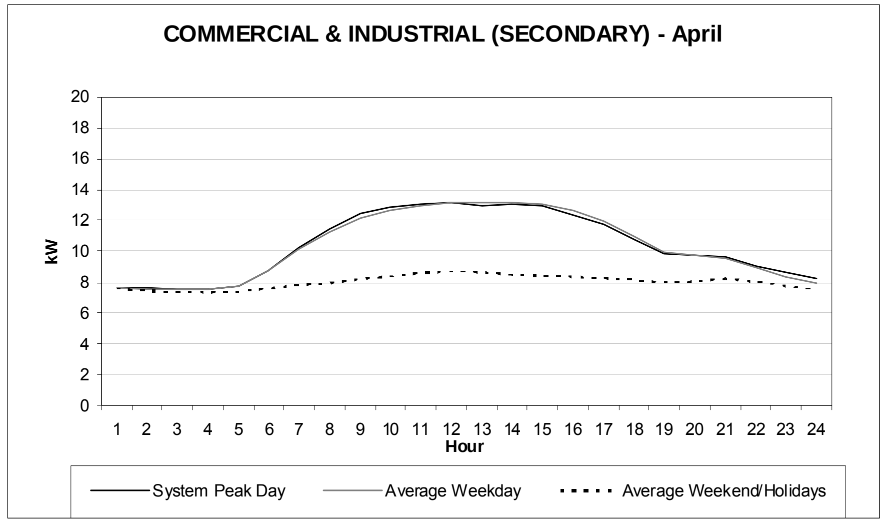


Figure 2.7-17 Commercial & Industrial (Secondary) May

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.3894	7.7394	7.6277
2	8.1677	7.6671	7.4697
3	7.9548	7.5286	7.3524
4	7.9234	7.5382	7.3088
5	8.3423	7.8147	7.3710
6	9.1075	8.7361	7.4786
7	10 2739	9.9317	7.5577
8	11.5252	11.2558	7.9182
9	12 9819	12.3158	8.3591
10	13 9896	12.9260	8.7462
11	14.6264	13.3668	9.1048
12	14.8525	13.5685	9.2718
13	15 0433	13.6321	9.2894
14	15.3787	13.7288	9.1976
15	15.1896	13.6259	9.1583
16	14.8663	13.1865	9.0696
17	14.1726	12.4987	9.0025
18	13 2175	11.4684	8.8124
19	11.8957	10.3917	8.4805
20	11 2352	10.0211	8.2996
21	10.7925	9.8037	8.4497
22	10.4014	9.2720	8.2720
23	9.3786	8.5769	7.8828
24	8.8238	8.1409	7.6227

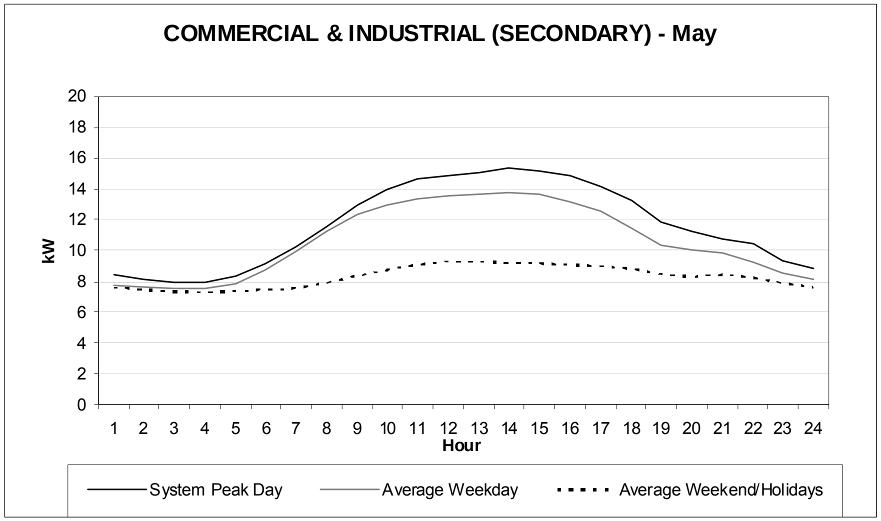


Figure 2.7-18 Commercial & Industrial (Secondary) June

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.2687	8.2908	8.1764
2	8.1815	8.1234	7.9175
3	8.1020	7.9565	7.7409
4	8.3681	8.0133	7.6397
5	8.7126	8.3665	7.6786
6	9.5490	9.1916	7.7429
7	10.7686	10.4034	8.0164
8	12.3874	11.8256	8.4668
9	13.7331	12.9872	9.0341
10	14 9134	13.8733	9.6161
11	15.7311	14.5289	10.0101
12	16 2568	14.9386	10.2551
13	16.5887	15.2202	10.3640
14	16 9987	15.4909	10.2871
15	17.1946	15.4378	10.2602
16	16.6196	15.0847	10.2098
17	15.8027	14.4949	10.0992
18	14.6500	13.3696	9.8680
19	12.7338	11.9678	9.4903
20	12.1895	11.4203	9.2545
21	11 9220	11.0376	9.2591
22	11.3446	10.4727	9.1064
23	10.1847	9.4363	8.6044
24	9.4178	8.8330	8.2206

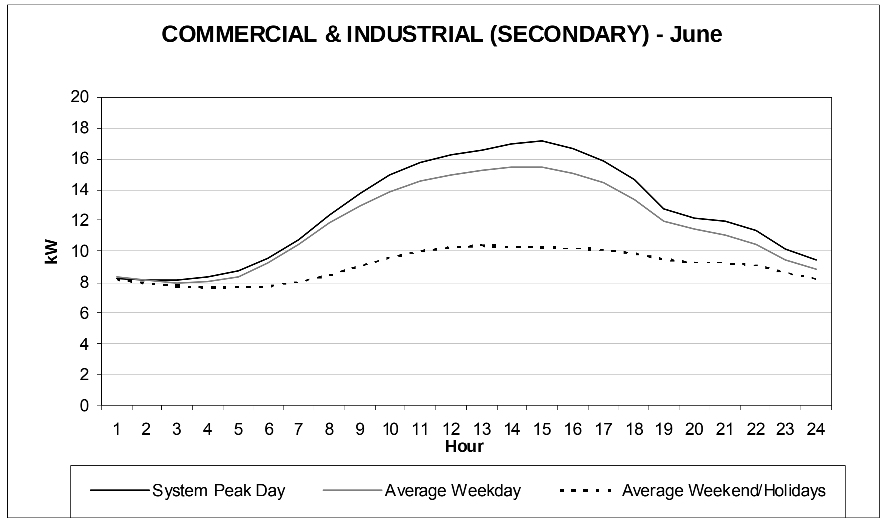


Figure 2.7-19 Commercial & Industrial (Secondary) July

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.9492	8.5183	8.2688
2	8.7058	8.3337	8.0108
3	8.6292	8.2174	7.8671
4	8.6435	8.3051	7.7655
5	9.0492	8.6657	7.8183
6	10 2665	9.7520	7.9871
7	11.5806	10.8719	8.1445
8	13 0425	12.2194	8.6505
9	14.4183	13.3533	9.3072
10	15.3855	14.2466	10.0061
11	16 2923	14.9961	10.5911
12	16 9526	15.4603	10.9556
13	17.1407	15.7796	11.0917
14	17.1402	15.9403	11.0257
15	16.8919	15.7308	11.0255
16	16.3756	15.2397	10.9759
17	15.4155	14.6043	10.8097
18	14.1072	13.4145	10.6021
19	12.8727	12.1279	10.1939
20	12 2376	11.5941	9.9175
21	11.8344	11.2870	9.8638
22	11 2405	10.7258	9.5427
23	9.9214	9.6094	8.8701
24	9.1851	9.0004	8.4685

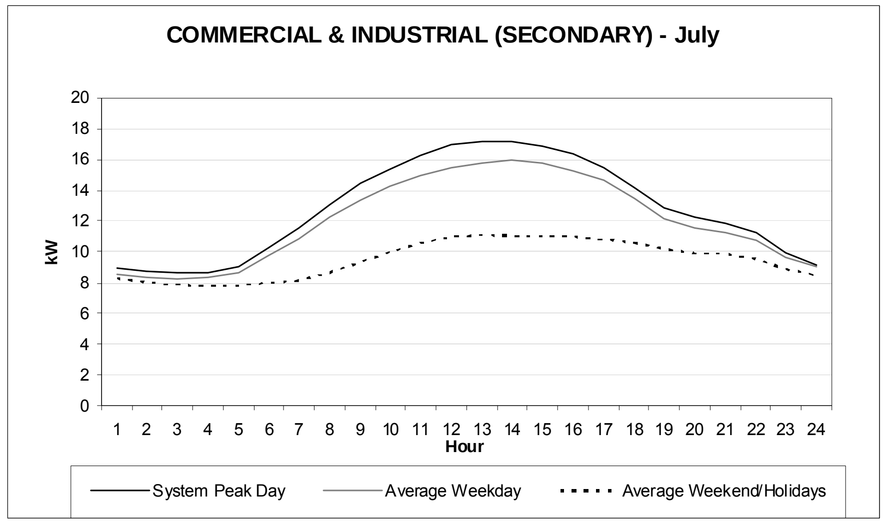


Figure 2.7-20 Commercial & Industrial (Secondary) August

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.6348	8.6040	8.5804
2	8.4535	8.4401	8.3412
3	8.3015	8.3216	8.1797
4	8.3353	8.4240	8.0538
5	8.6673	8.7828	8.0886
6	9.7266	9.9364	8.2981
7	11 0584	11.1024	8.4769
8	12.4813	12.3782	8.8207
9	13.8413	13.6459	9.4870
10	15.1258	14.6357	10.2205
11	16.1499	15.4761	10.8791
12	16.7858	15.9916	11.2818
13	16 9489	16.2376	11.4703
14	17.3663	16.4848	11.5264
15	17.6671	16.4773	11.5439
16	17.1723	15.9859	11.4844
17	16.3780	15.1421	11.3502
18	15 2938	13.8531	11.0600
19	13.6550	12.4204	10.5328
20	12 9893	11.8416	10.2967
21	12.4212	11.4184	10.2712
22	11.4048	10.5833	9.7939
23	10.1450	9.5502	9.2377
24	9.4682	8.9664	8.8819

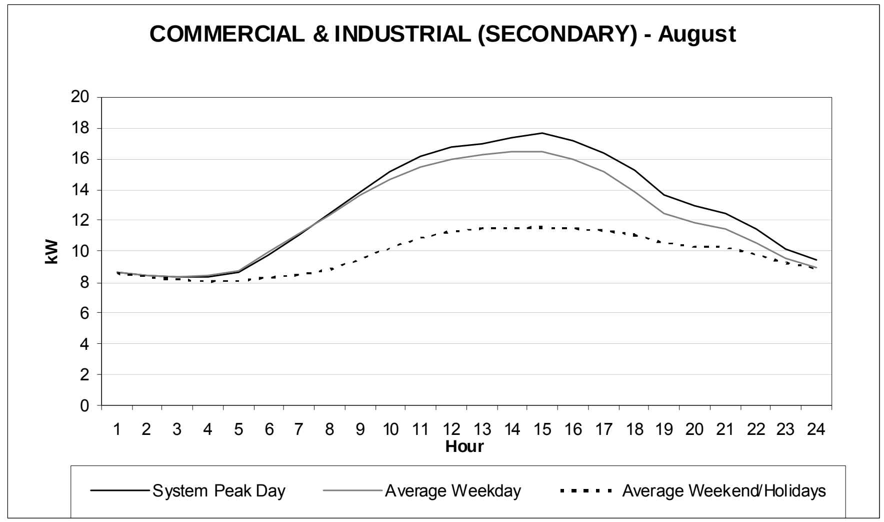


Figure 2.7-21 Commercial & Industrial (Secondary) September

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.1623	8.0876	7.8716
2	7.9772	7.9192	7.6669
3	7.8220	7.7273	7.4757
4	8.0626	7.7969	7.3706
5	8.4134	8.1092	7.4533
6	9.6146	9.1742	7.6794
7	10.7221	10.3596	7.9618
8	11.7071	11.2992	7.9609
9	13 0084	12.4859	8.4853
10	14.3197	13.4657	9.0755
11	15.1214	14.2285	9.6913
12	15.6139	14.6895	10.0832
13	15 9004	14.9686	10.1896
14	16.3172	15.3376	10.2322
15	16 2382	15.3580	10.3101
16	15.7205	14.9038	10.3676
17	15 0470	14.1662	10.3663
18	13 9644	13.0473	10.1065
19	12.4626	11.7404	9.6917
20	12 0115	11.4617	9.6938
21	11 2257	10.7441	9.3737
22	10.1748	9.8576	8.8409
23	9.2458	8.9944	8.3135
24	8.6275	8.4623	7.9984

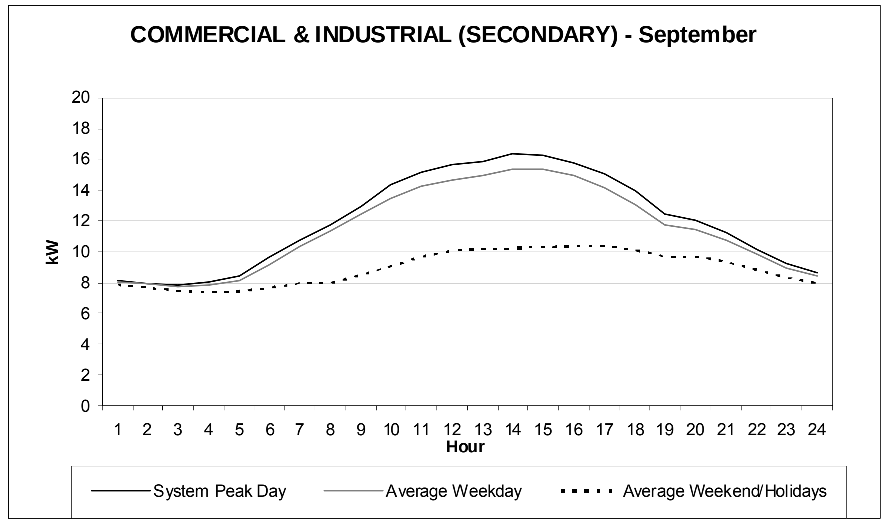


Figure 2.7-22 Commercial & Industrial (Secondary) October

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.6062	7.5353	7.2998
2	7.4516	7.4454	7.1430
3	7.2881	7.2851	7.0155
4	7.3436	7.3207	6.9328
5	7.6286	7.6076	6.9924
6	8.7279	8.5735	7.2201
7	10 0890	9.9128	7.5778
8	11 0439	10.9800	7.6095
9	12 0086	11.6603	7.6703
10	12.8813	12.1663	8.0159
11	13.6537	12.6779	8.4440
12	14 2245	12.9553	8.6683
13	14.4323	13.0825	8.6977
14	14.6879	13.2484	8.5991
15	14.7296	13.1391	8.5415
16	14.1860	12.6909	8.5132
17	13 2117	11.9349	8.4321
18	12.1087	11.0127	8.3339
19	11 0761	10.3390	8.4530
20	10.7632	10.0490	8.3860
21	10 0665	9.4911	8.1708
22	9.1927	8.8471	7.8334
23	8.4446	8.1959	7.4911
24	7.9557	7.8056	7.2777

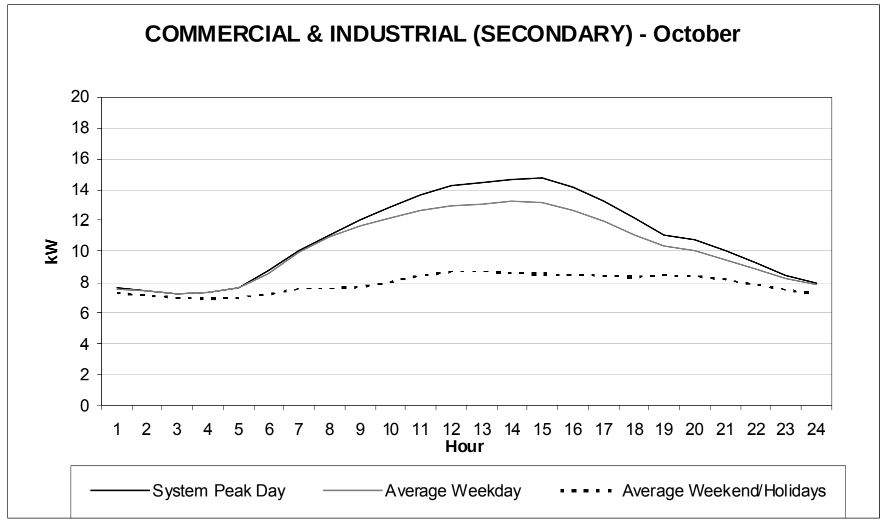


Figure 2.7-23 Commercial & Industrial (Secondary) November

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.7501	7.8577	7.7909
2	7.7228	7.7708	7.6355
3	7.8998	7.7025	7.5851
4	8.0161	7.8209	7.5687
5	8.2902	8.0994	7.6562
6	9.1961	8.9967	7.9280
7	10.4831	10.2557	8.2594
8	11.4183	11.2185	8.1347
9	12 2577	11.7876	8.1553
10	12.6460	12.1136	8.3144
11	12.8802	12.3922	8.5268
12	13 0848	12.5050	8.5866
13	13.1217	12.4850	8.4971
14	13 0733	12.4775	8.3723
15	12.8195	12.3283	8.3028
16	12.4932	11.9617	8.2664
17	12.1927	11.5833	8.4834
18	11.7518	11.1415	8.8896
19	10 9301	10.4070	8.7443
20	10.4897	10.0083	8.5899
21	10.1640	9.6056	8.3953
22	9.6296	9.0928	8.1780
23	9.0606	8.4890	7.9215
24	8.7655	8.1532	7.7450

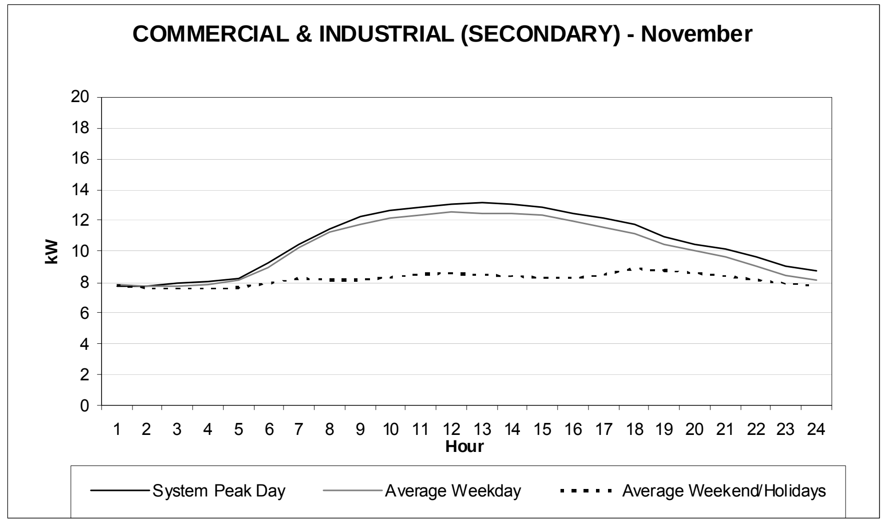


Figure 2.7-24 Commercial & Industrial (Secondary) December

COMMERCIAL & INDUSTRIAL (SECONDARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.0037	7.9105	7.9043
2	8.7987	7.7938	7.7816
3	8.8140	7.7519	7.7446
4	8.8992	7.8415	7.7473
5	9.0418	8.1057	7.8487
6	9.4478	8.9998	8.1126
7	9.9745	10.1947	8.5372
8	10.1811	11.1584	8.5311
9	10 0895	11.6443	8.3865
10	10 2577	11.9516	8.4903
11	10.4360	12.1748	8.6264
12	10.4696	12.2548	8.5941
13	10 2414	12.1813	8.4622
14	10.1822	12.1596	8.3233
15	10 2729	11.9941	8.2382
16	10.3213	11.6525	8.2306
17	10.5701	11.4673	8.5374
18	10.8800	11.1539	8.9780
19	10.4365	10.3394	8.7799
20	10.1989	9.9899	8.6504
21	10 0058	9.6145	8.5365
22	9.7352	9.1311	8.3237
23	9.3090	8.5328	8.0598
24	9.2283	8.1905	7.9180

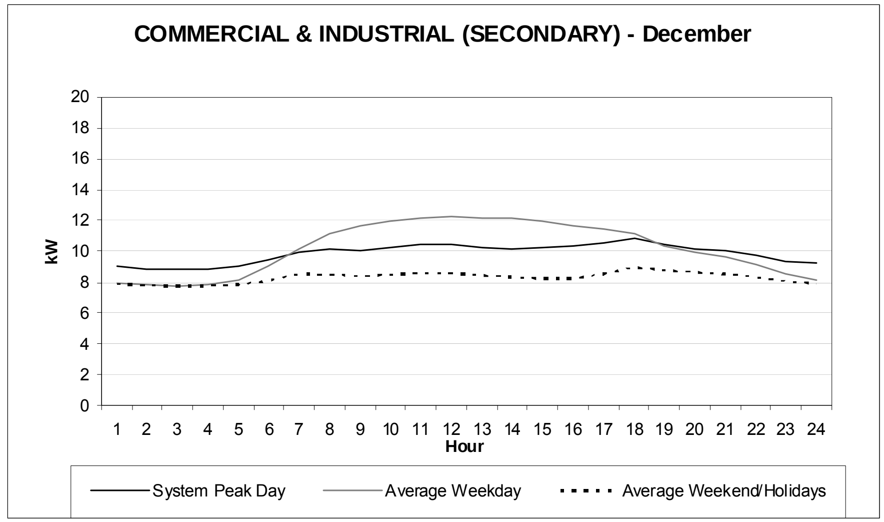


Figure 2.7-25 Commercial & Industrial (Primary) January

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	634.0537	593.8431	562.2665
2	624.4625	587.8894	559.2923
3	612.7073	582.6943	555.5461
4	623.4924	587.1666	552.4311
5	636.6664	600.3537	554.9488
6	658.7008	623.5187	562.4669
7	685.3389	656.6828	570.9132
8	707.5866	682.3368	572.6057
9	726.8331	705.3827	577.5959
10	735.3058	718.7820	584.3108
11	738.2335	722.1699	588.4797
12	735.9429	721.3210	589.6380
13	733.2276	715.5718	587.8034
14	732.1676	720.4684	585.6474
15	726.5024	716.8556	583.6227
16	711.2284	704.5516	577.6183
17	696.4223	683.9095	572.0983
18	695.6245	673.7691	578.9436
19	684.5524	655.2676	577.6858
20	678.3186	645.6444	575.8019
21	673.6547	637.2104	571.8415
22	662.9527	626.2484	568.8470
23	652.2062	613.5437	564.9806
24	644.2116	604.0331	561.4409

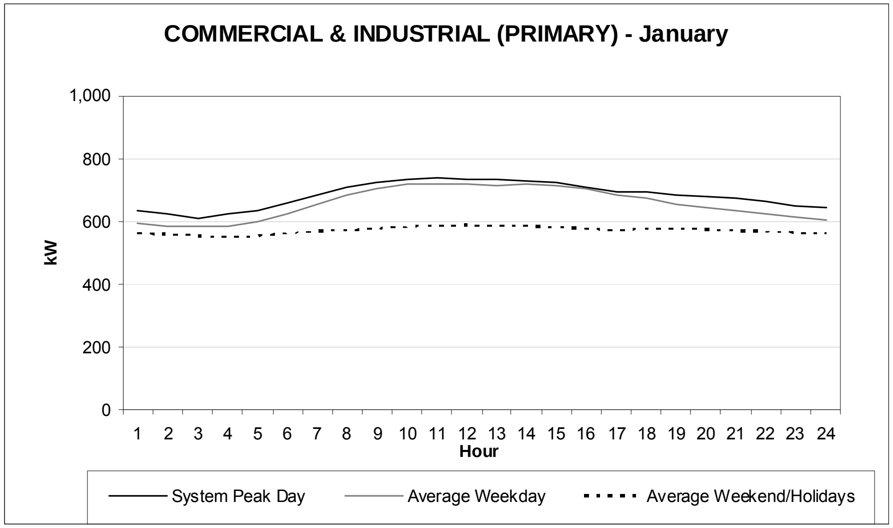


Figure 2.7-26 Commercial & Industrial (Primary) February

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	568.0863	590.7618	564.1499
2	564.7851	585.9476	560.4223
3	560.4729	581.3329	557.3908
4	564.7035	583.6474	553.0906
5	583.1681	598.1438	558.2955
6	606.9457	622.3496	565.9066
7	644.5903	656.3673	574.6861
8	673.6968	678.0376	575.3295
9	700.9727	704.0142	586.6089
10	721.4789	719.1201	595.1030
11	727.9250	724.3215	600.0904
12	732.6741	725.3511	602.8936
13	726.6458	718.5230	599.1616
14	733.0577	721.0604	595.8562
15	734.0395	719.7511	594.9180
16	718.5550	705.3583	588.1053
17	699.6733	685.7281	579.2503
18	684.1552	669.9420	581.9980
19	668.8200	654.9408	586.2191
20	655.7512	644.5997	583.0514
21	646.8919	636.6870	578.4175
22	636.1388	625.4174	573.9735
23	624.1250	611.0660	569.8917
24	614.7018	599.9249	565.6704

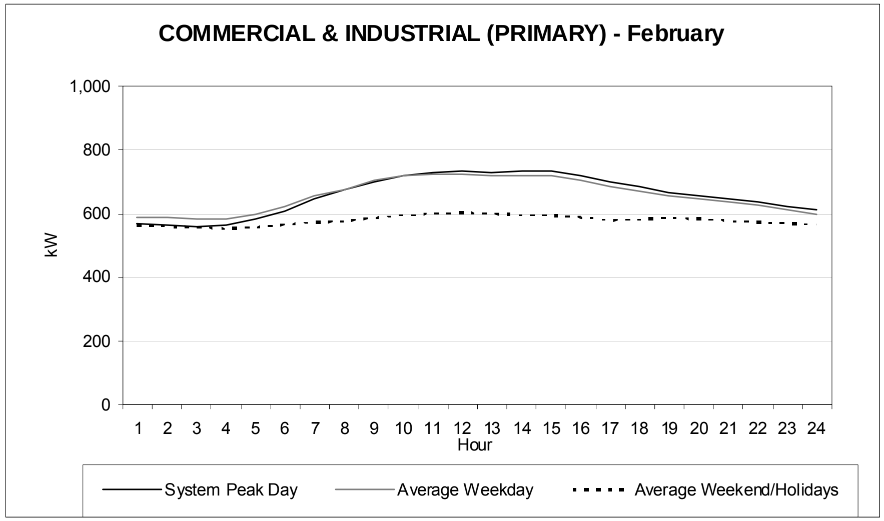


Figure 2.7-27 Commercial & Industrial (Primary) March

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	553.2934	572.6416	556.8109
2	553.2070	568.3047	553.6147
3	550.6985	564.8067	552.5560
4	551.9423	566.2438	548.1205
5	569.5467	580.1834	550.3008
6	592.8817	603.8256	558.8617
7	622.6232	636.7800	565.5699
8	656.5255	662.6820	566.4417
9	692.5070	690.3940	575.8318
10	710.5996	708.3885	583.8342
11	713.7568	715.3323	589.7903
12	717.3051	717.6384	592.1766
13	714.3995	712.7866	591.3625
14	718.8516	720.0101	591.3383
15	715.8538	718.1516	588.4862
16	696.5103	703.9812	579.3165
17	671.0636	679.2604	568.2925
18	649.6448	658.6651	564.0960
19	637.1644	640.3674	563.5584
20	623.5230	628.2874	567.8367
21	612.8071	619.2227	565.0752
22	602.0176	607.7451	561.3906
23	587.5383	594.5063	557.0186
24	579.5100	584.2859	552.8396

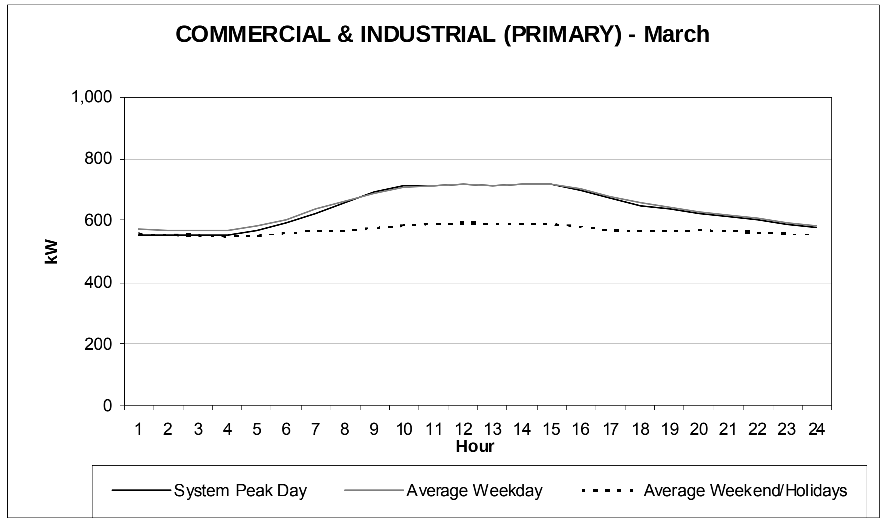


Figure 2.7-28 Commercial & Industrial (Primary) April

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	561.8729	570.3597	549.5050
2	558.0755	565.0111	544.7756
3	552.6966	560.7000	541.2732
4	551.7420	562.2219	537.7119
5	564.7027	576.3259	538.9664
6	591.0075	599.4202	546.4247
7	628.4325	631.8982	552.1647
8	656.2954	659.7904	555.1423
9	674.8875	688.4626	565.0087
10	706.3517	703.5795	573.0781
11	712.2760	714.7035	579.9404
12	715.7626	717.6513	583.4568
13	705.9520	712.9885	585.3332
14	711.4531	720.9461	586.2162
15	713.4454	719.1271	583.6490
16	700.7496	707.5867	579.9537
17	677.3857	687.7000	572.6172
18	655.7393	663.0486	568.5859
19	635.9251	642.2145	562.8640
20	625.3930	627.9977	564.5140
21	620.2049	623.0560	566.3203
22	609.4337	611.6917	561.1149
23	595.9564	594.7448	556.2805
24	588.7530	581.7713	550.3548

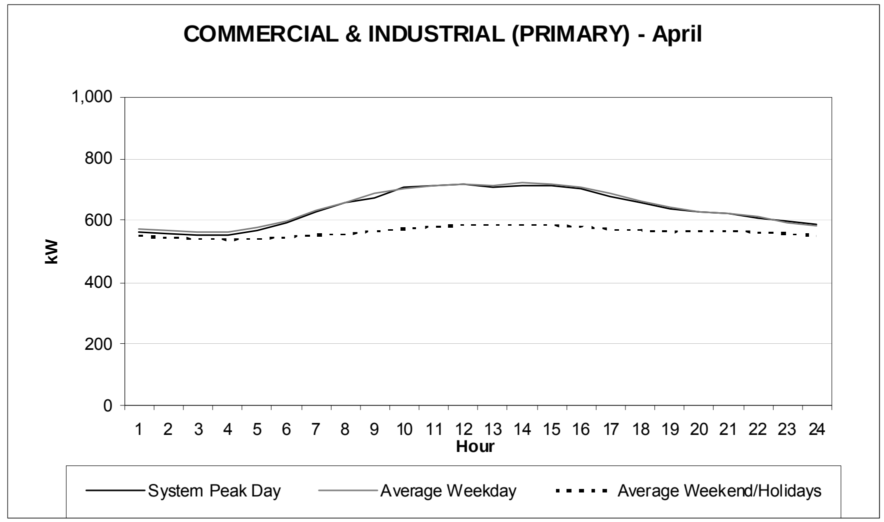


Figure 2.7-29 Commercial & Industrial (Primary) May

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	612.0931	576.6426	556.8134
2	603.4912	570.4737	552.2930
3	594.6661	564.5771	547.2569
4	594.4936	565.6880	544.0045
5	606.8490	580.8892	545.9991
6	624.4609	602.9843	550.9846
7	655.7800	633.8253	552.3310
8	691.4209	668.0399	558.7288
9	728.8228	698.5643	568.0222
10	756.1295	715.3876	576.3257
11	764.5470	724.5940	583.5058
12	769.1128	729.3083	588.8684
13	765.8938	725.7044	589.6858
14	768.5125	733.1228	592.8742
15	769.5914	734.8097	595.1370
16	751.7825	722.9113	592.5472
17	742.2037	703.7260	589.6906
18	724.3070	677.9307	582.7902
19	696.4545	655.1747	574.4730
20	682.1485	637.7719	570.3025
21	675.2478	631.7473	569.9345
22	659.1264	621.2157	566.4187
23	635.6305	605.1136	559.3630
24	616.0842	592.0934	552.9130

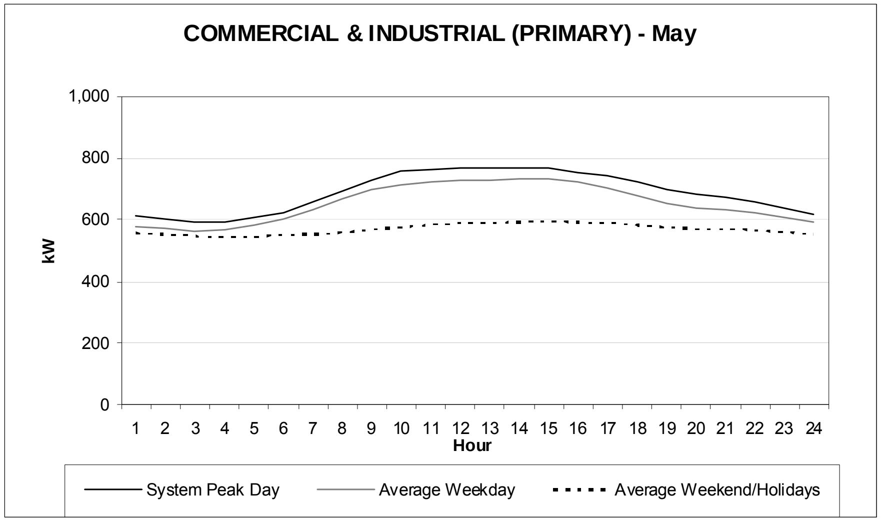


Figure 2.7-30 Commercial & Industrial (Primary) June

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	597.2997	606.5269	586.9656
2	592.3083	597.6191	580.6081
3	590.5176	590.5744	573.0949
4	593.3034	590.1902	568.4914
5	610.4326	604.3806	571.2837
6	635.8312	624.1439	575.4614
7	671.1563	658.6132	580.9260
8	719.4879	697.9810	591.1215
9	762.8585	734.9424	604.3979
10	789.6685	754.3665	616.4036
11	805.1829	767.8625	624.3104
12	804.9668	773.9046	629.5461
13	809.0459	774.0329	631.3305
14	821.0635	784.9860	632.9618
15	822.5819	786.1306	634.1155
16	809.5072	776.5814	632.9723
17	791.0908	758.5485	629.1145
18	764.3843	731.8258	620.9131
19	668.8167	701.4853	609.2799
20	648.4863	680.7030	601.4756
21	668.2947	671.4825	599.6225
22	669.3122	661.5260	598.3964
23	645.6620	640.4835	590.5783
24	624.0245	625.2809	583.1792

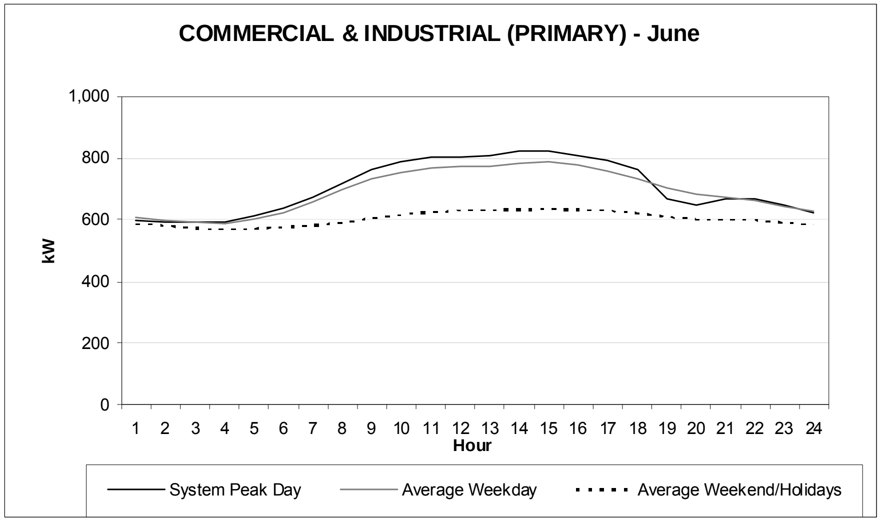


Figure 2.7-31 Commercial & Industrial (Primary) July

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	658.5949	638.0135	605.8430
2	646.6978	629.3251	599.7723
3	639.1730	621.6719	591.6629
4	636.7020	621.7959	587.8670
5	651.0434	635.3082	589.7764
6	674.5570	659.0372	595.4334
7	708.9900	691.8981	600.0800
8	743.7610	732.2023	611.7756
9	779.4916	766.2338	629.3113
10	806.9224	787.7976	642.7795
11	815.9854	797.7528	651.7641
12	828.7806	802.7613	657.6468
13	840.8269	803.9840	659.1388
14	837.5539	810.5029	662.0596
15	830.4201	806.5468	661.8918
16	828.3374	796.8288	660.6703
17	809.1716	780.5804	655.8984
18	775.4917	755.0199	646.2267
19	751.2519	729.1147	633.8412
20	735.5918	709.0905	628.1035
21	720.5244	698.1067	624.8098
22	710.5914	687.6176	621.1907
23	686.7666	667.1113	610.5428
24	673.5712	652.0080	602.0571

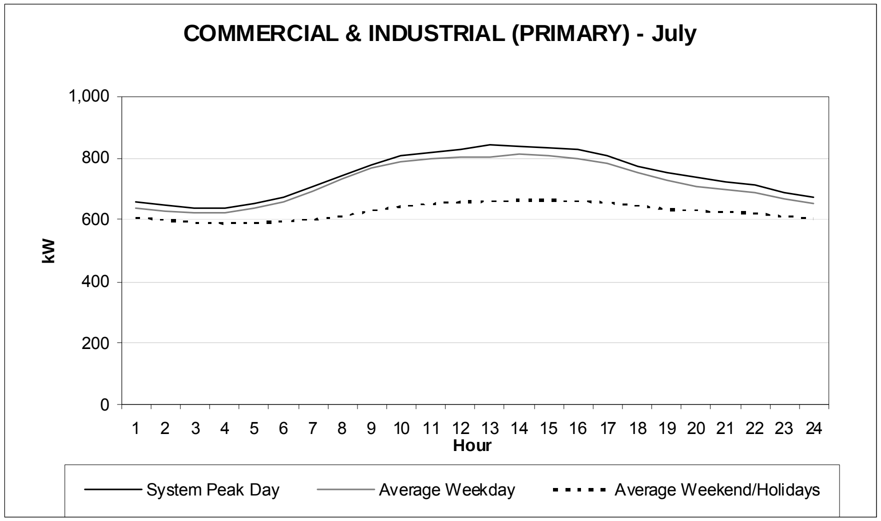


Figure 2.7-32 Commercial & Industrial (Primary) August

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	636.5240	624.4225	609.7379
2	622.8800	617.5416	603.9663
3	618.5167	610.8121	595.7567
4	617.9319	611.6250	590.4868
5	624.6630	624.5460	592.6413
6	647.7972	651.3706	599.3706
7	684.8070	686.4046	604.1973
8	737.2204	723.0028	612.9855
9	780.4381	759.7695	628.7902
10	799.4241	785.1900	645.5334
11	821.3788	799.2931	656.7725
12	832.0464	805.1372	664.0233
13	835.4316	806.2544	667.0659
14	844.1025	816.9097	671.4654
15	845.1095	815.8112	671.4655
16	835.6363	801.4661	669.2498
17	812.9399	780.1450	664.6928
18	772.1445	745.6477	657.9528
19	743.8144	715.1763	648.0406
20	721.7896	699.4540	642.6610
21	712.7609	690.6999	641.1003
22	693.1105	675.0357	634.3521
23	670.7758	654.5681	624.7793
24	659.0432	639.1663	615.1258

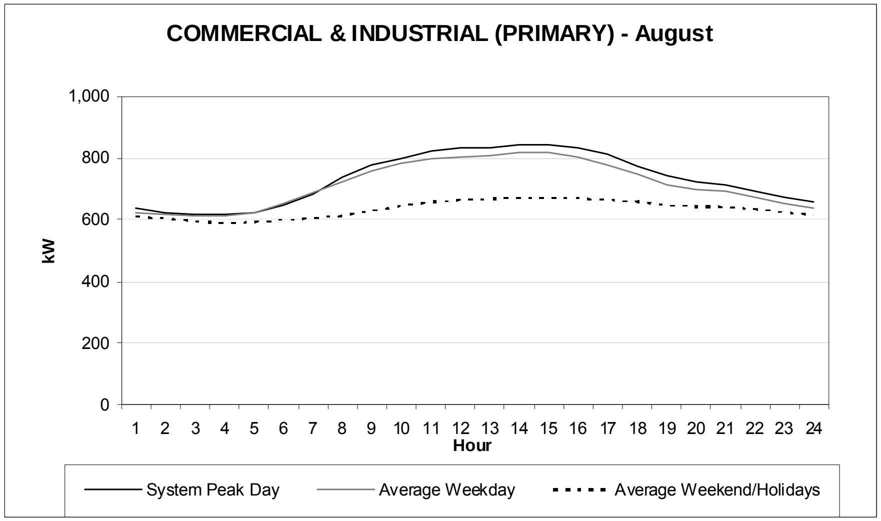


Figure 2.7-33 Commercial & Industrial (Primary) September

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	628.9109	618.4243	585.5052
2	620.4389	610.2936	579.2159
3	609.3576	600.9791	571.0816
4	609.5659	600.4572	565.4339
5	621.1049	614.4055	568.3572
6	646.3694	640.0600	577.9242
7	682.4298	678.0752	586.4682
8	710.2586	705.0595	586.4117
9	747.3444	738.5203	597.0889
10	784.3921	765.0616	613.1609
11	804.2488	782.0417	629.0496
12	810.1946	792.1422	639.2054
13	803.8604	794.0273	643.5462
14	821.5849	808.4208	647.2561
15	824.6959	808.1764	648.4904
16	809.2477	795.9864	647.5939
17	790.4205	776.5803	644.3104
18	761.9830	747.5000	639.2987
19	726.5712	716.3620	629.1612
20	715.2477	704.2899	626.1698
21	701.5868	689.1854	618.0066
22	682.2303	670.6009	608.6178
23	662.8909	649.6015	597.8154
24	645.3389	632.9408	589.3769

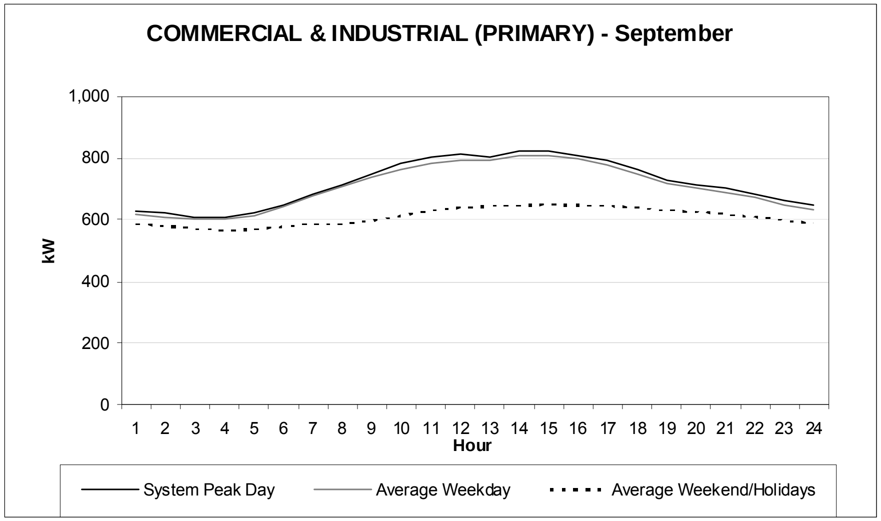


Figure 2.7-34 Commercial & Industrial (Primary) October

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	619.1993	608.6619	580.0760
2	607.9885	601.4355	575.3681
3	599.5434	595.0001	570.3702
4	595.0334	595.2406	567.9168
5	607.4755	608.2531	570.7049
6	638.7430	635.8509	578.4036
7	680.4289	677.1384	589.7168
8	710.5494	708.1245	590.9654
9	736.7557	729.8292	591.7865
10	766.6811	742.8971	596.2517
11	783.6047	749.5712	602.2001
12	798.1092	755.7329	606.2859
13	797.5411	752.9130	608.2663
14	814.1446	764.7857	610.4340
15	820.3719	766.1028	610.0406
16	804.6580	752.4694	609.0232
17	784.6921	734.7058	606.6964
18	751.6281	705.7676	602.3649
19	724.0936	686.4055	600.5565
20	711.4901	673.9905	600.0192
21	697.5338	661.7851	593.5088
22	678.9817	648.6053	587.5329
23	656.3554	632.6199	582.7243
24	642.2545	621.5484	577.9134

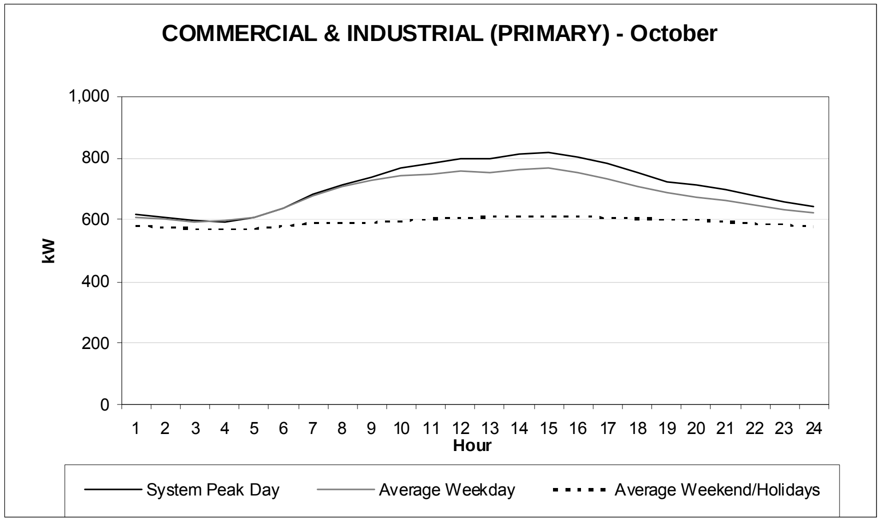


Figure 2.7-35 Commercial & Industrial (Primary) November

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	593.4696	613.2191	588.5148
2	596.5157	608.9742	584.8387
3	597.4213	605.0798	579.7657
4	602.7543	606.7315	577.2762
5	622.6039	620.9561	580.4702
6	654.0979	647.8562	588.0345
7	694.2368	684.1850	595.2510
8	711.5707	711.3956	593.8452
9	732.6725	726.4730	593.1402
10	747.1191	734.8336	595.0413
11	752.9362	737.4445	598.1880
12	761.0662	738.6064	599.3235
13	764.4094	733.4564	599.4173
14	764.6554	740.8205	598.4967
15	761.0779	737.7681	596.8057
16	748.0039	727.6059	594.4013
17	731.1398	714.0573	594.9794
18	726.3138	692.9278	601.4078
19	705.6596	677.3707	599.1045
20	696.1943	667.3016	597.9472
21	687.1038	657.2191	595.1726
22	674.7612	648.6829	592.2862
23	662.5983	636.3867	588.5951
24	654.7929	627.0345	586.7963

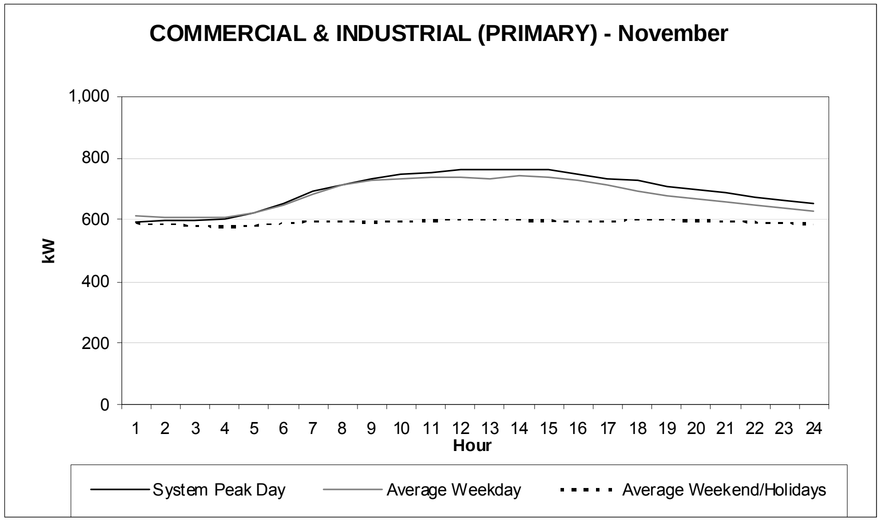


Figure 2.7-36 Commercial & Industrial (Primary) December

COMMERCIAL & INDUSTRIAL (PRIMARY) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	592.7095	605.2011	578.8713
2	585.8260	599.2546	574.9340
3	582.3826	594.3254	570.7399
4	582.6505	597.1404	569.0442
5	587.6000	611.1287	572.2099
6	593.3775	635.7328	579.9580
7	603.1411	671.7285	591.1010
8	604.6061	700.4923	591.8185
9	608.9275	719.4167	594.5547
10	615.8777	728.6033	599.4619
11	614.4813	730.7166	600.4995
12	614.3180	730.0789	597.8201
13	613.6454	725.0552	593.8669
14	614.9212	730.1836	592.7955
15	611.1145	727.8081	591.8295
16	609.2096	715.1238	588.8053
17	604.8012	698.3343	587.2828
18	611.8338	680.7149	596.5491
19	605.2175	664.7035	592.3924
20	602.0679	653.1747	589.7881
21	600.2269	643.2843	586.9632
22	593.2086	634.0932	583.4509
23	584.2591	623.3849	578.1254
24	580.5399	614.7665	575.6772

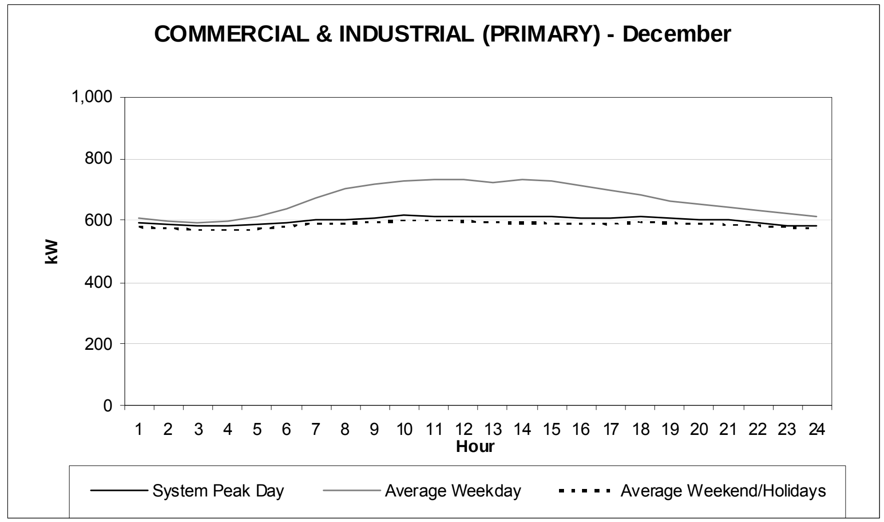


Figure 2.7-37 Commercial & Industrial (Transmission) January

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6877.3350	6375.5481	6085.2952
2	6805.9261	6185.1512	6157.4985
3	7039.3902	6320.9155	6036.9443
4	7055.0778	6400.3158	6078.1207
5	7006.9032	6367.2901	6035.8867
6	6897.2434	6404.5603	6090.9586
7	5758.4159	6436.8959	6004.7440
8	5900.9764	6199.2863	5861.1997
9	5903.0531	6259.9350	5908.9303
10	7032.3759	6302.9682	5773.8835
11	6874.4222	6458.2688	5958.0044
12	6855.8998	6409.9271	6028.9057
13	7069.6737	6475.7187	6084.7834
14	6966.7669	6514.8361	6103.8138
15	7091.8920	6453.9799	6011.9905
16	7190.3458	6449.6486	5754.4310
17	7099.2728	6372.6177	5922.6885
18	7015.7024	6371.2599	5930.2350
19	6827.9703	6308.1436	5862.8124
20	6706.4137	6320.9707	6037.4881
21	5727.4246	6525.2051	6051.2616
22	6193.9342	6383.6433	5935.8728
23	6481.3274	6594.4657	5998.3737
24	6745.7977	6550.8153	6160.5322

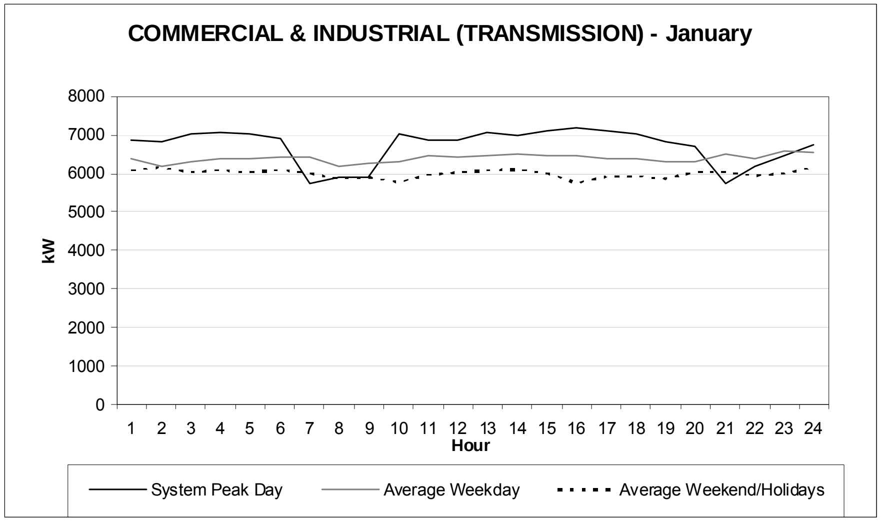


Figure 2.7-38 Commercial & Industrial (Transmission) February

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5835.5121	6737.9856	6535.6174
2	5846.5079	6703.1048	6375.6988
3	5686.6540	6632.3469	6586.7870
4	5773.6339	6686.1269	6450.4940
5	6037.1352	6763.4848	6508.9782
6	6092.3681	6606.3025	6450.4027
7	5984.5371	6669.2796	6358.5033
8	6366.9042	6631.5515	6057.7187
9	6308.2532	6545.0660	6118.4095
10	6501.7782	6484.6336	6169.3520
11	6386.6651	6317.4276	5931.7869
12	6707.5263	6534.3552	6060.2422
13	6493.0602	6577.6733	6051.7561
14	6673.9806	6603.8916	5996.2064
15	6819.2906	6645.0200	6130.1691
16	6682.3179	6680.1627	5949.8677
17	6748.4201	6602.5095	6215.4588
18	6211.8856	6585.5314	6229.9568
19	5644.6489	6366.3505	6081.2651
20	6579.3358	6391.4388	6006.2677
21	6935.4689	6616.1017	6221.6583
22	6820.7583	6635.9720	6173.1723
23	6887.9673	6757.3279	5979.1575
24	6965.6856	6781.1908	6081.3878

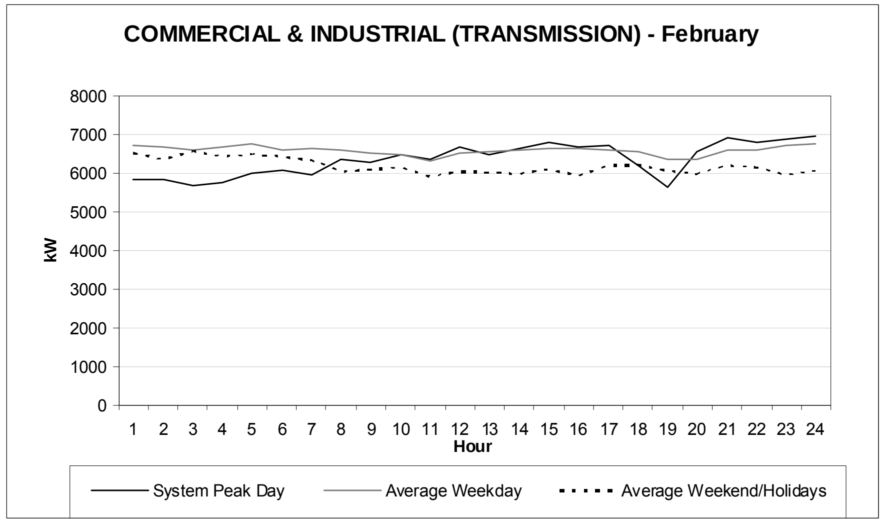


Figure 2.7-39 Commercial & Industrial (Transmission) March

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4166.4103	6568.6235	6378.0907
2	4353.9538	6666.3773	6281.5681
3	4152.0849	6655.9310	6459.6315
4	4286.9147	6620.3416	6237.0744
5	4346.1809	6473.4276	6177.9315
6	6056.5424	6669.6761	6183.1796
7	6040.2225	6714.2795	6113.2359
8	6434.0129	6720.6082	5965.2518
9	6471.9627	6613.3132	5731.6035
10	6620.3693	6679.9569	5863.0177
11	6268.8941	6722.0729	6045.2008
12	6766.4652	6785.0030	5854.7689
13	6406.3231	6722.4485	5970.5934
14	6569.6924	6843.0034	6040.5502
15	6270.0062	6918.5016	6103.7982
16	6101.2245	6807.2523	6021.3930
17	6127.4043	6858.6172	6058.1422
18	6207.8273	6607.2496	6010.6717
19	6371.7659	6585.1927	5765.7721
20	6945.0964	6519.8240	5789.2554
21	6957.8633	6544.4753	6022.7468
22	7051.4978	6731.3319	6049.5375
23	6962.1837	6758.5249	6030.0942
24	5715.3232	6660.1633	6151.9044

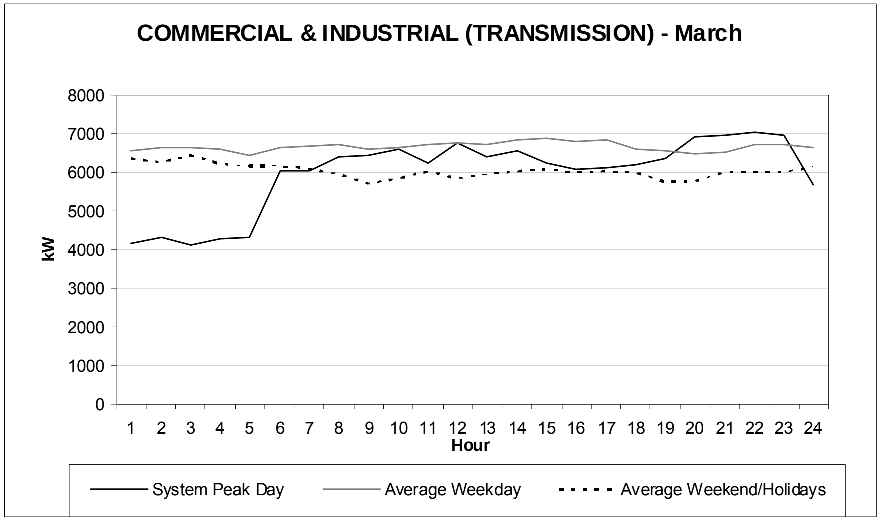


Figure 2.7-40 Commercial & Industrial (Transmission) April

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7079.5066	6785.7165	6329.2408
2	7046.6558	6797.7604	6480.0697
3	6466.2929	6872.1283	6235.7524
4	6742.8553	6745.1652	6391.3247
5	6895.2899	6784.7081	6214.2800
6	6837.9914	6758.3091	6446.8764
7	6858.7554	6730.1124	6477.4608
8	6310.4239	6783.0340	6183.3323
9	7214.9626	6843.1408	6083.2324
10	7330.5849	7022.8023	6133.2948
11	6719.8736	6899.7514	5966.9285
12	7654.2939	6897.1964	6109.7498
13	7348.5232	6873.8994	6152.0653
14	7034.9976	6990.8503	6173.8466
15	7275.8111	6888.0172	6284.4415
16	7166.0581	6840.7194	6403.0888
17	7464.5788	6700.6447	6327.7780
18	6317.0397	6544.4773	6277.2593
19	6633.1311	6441.0910	6166.1833
20	7034.1500	6460.9145	6204.6272
21	7305.7842	6471.1387	6280.2218
22	7255.9884	6436.1218	5716.0160
23	7245.2018	6498.2071	5714.0184
24	6549.0575	6619.1016	6335.8716

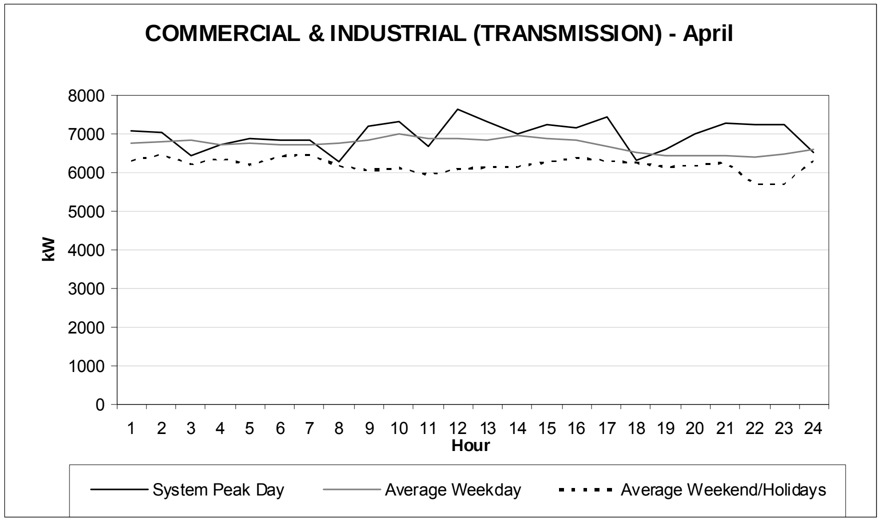


Figure 2.7-41 Commercial & Industrial (Transmission) May

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7282.4881	6480.3473	6124.0459
2	7299.5082	6402.9015	6100.7727
3	7142.3669	6365.3616	6049.8242
4	7190.9544	6284.4608	6065.1566
5	7275.2801	6311.5510	5994.4706
6	6995.6552	6383.9702	6066.3347
7	6053.9054	6338.7443	5889.4545
8	6511.9831	6229.4506	5785.4551
9	5754.4963	6342.0006	5616.1317
10	6419.2535	6418.2001	5677.2403
11	6457.9635	6530.2296	5907.3817
12	6503.4378	6597.4839	5884.0946
13	6457.5002	6555.9701	5871.4999
14	6473.9078	6753.8351	5944.2830
15	6392.6095	6758.9369	5922.9226
16	6095.9157	6653.1865	5847.9622
17	6364.6348	6585.1995	5691.8231
18	6489.0940	6484.9600	5612.5852
19	6413.3924	6452.0680	5645.6441
20	5038.0367	6448.2753	5611.8056
21	4974.6854	6448.5577	5663.3532
22	5320.4738	6341.8789	5647.7301
23	6233.9186	6432.2641	5671.3429
24	6215.8739	6466.3750	5897.1539

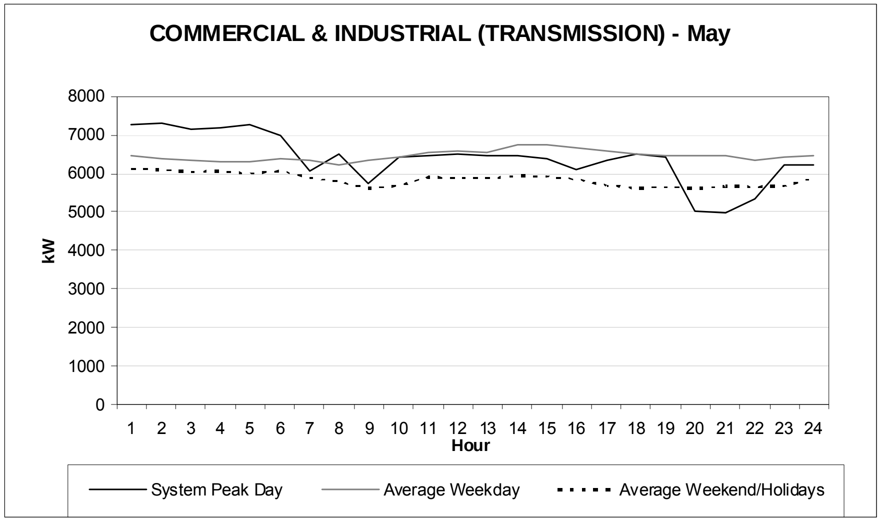


Figure 2.7-42 Commercial & Industrial (Transmission) June

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6715.4562	6580.7699	6119.5825
2	6816.0095	6615.0914	6497.5764
3	6593.2209	6604.4940	6174.5328
4	6678.5469	6573.8140	6287.6577
5	6823.7574	6609.0745	6251.2492
6	6433.8640	6498.0093	6094.2336
7	6135.9900	6570.9215	6068.0898
8	7016.7477	6569.0146	6048.8248
9	7222.3310	6531.1400	5942.9763
10	7496.2826	6586.1326	6116.6061
11	7125.3212	6601.9965	5977.0144
12	7459.1722	6761.9037	6113.9711
13	7277.1660	6652.1473	6112.0113
14	7526.1283	6515.7260	6277.9843
15	7389.9930	6638.2968	5997.7121
16	7491.3954	6798.9784	6155.2996
17	7340.0504	6640.5182	6126.6247
18	7158.3572	6679.8675	5658.8913
19	6828.4805	6396.3161	5802.6816
20	6785.3726	6769.4924	5855.5520
21	6735.8528	6745.1732	5974.5003
22	5468.4505	6656.8087	5952.2412
23	5442.7596	6783.6924	5901.4272
24	6033.6477	6782.9422	5844.1798

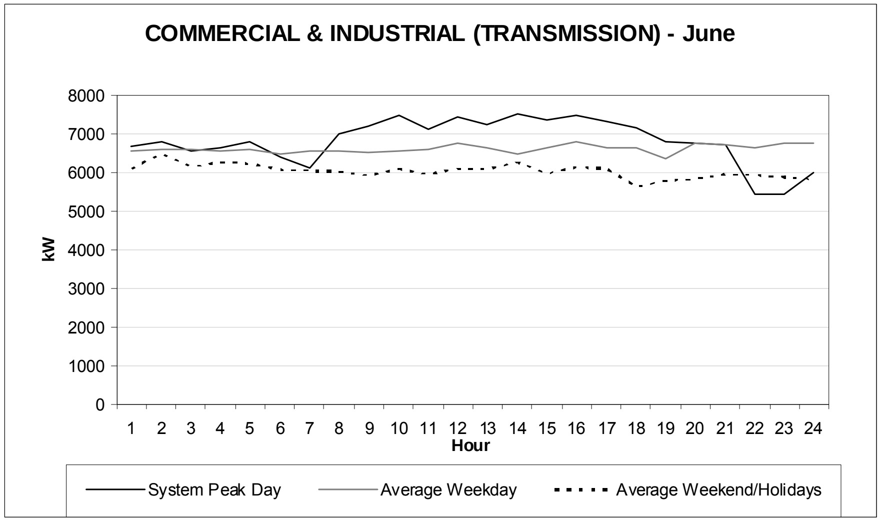


Figure 2.7-43 Commercial & Industrial (Transmission) July

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7188.3140	6710.4671	6343.8083
2	7114.8690	6721.2379	6221.0257
3	7218.3303	6704.8693	6348.0593
4	7053.5419	6495.2511	6367.3258
5	7047.1328	6690.7363	6336.9961
6	7277.5784	6686.2856	6252.4044
7	6649.7555	6713.0124	6179.1466
8	6962.3234	6712.8690	6002.8568
9	7473.9126	6671.2988	6143.0734
10	7401.8112	6566.5465	6298.1556
11	7553.3886	6700.4291	6355.5911
12	7671.5052	6562.2058	6309.6063
13	7153.1071	6704.7381	6302.5487
14	6909.2033	6750.0262	6296.4085
15	7164.6701	6610.6882	6053.2125
16	7462.3413	6526.7602	6248.5243
17	7369.3341	6538.0442	6299.7267
18	7486.7184	6309.1369	6061.5056
19	7145.1273	6350.6500	6104.4648
20	6621.8875	6584.1430	6051.4033
21	6239.2288	6675.9517	5996.3882
22	7304.0572	6505.3155	5953.4374
23	7471.7772	6602.8107	6047.2005
24	6948.0174	6647.8675	6244.6003

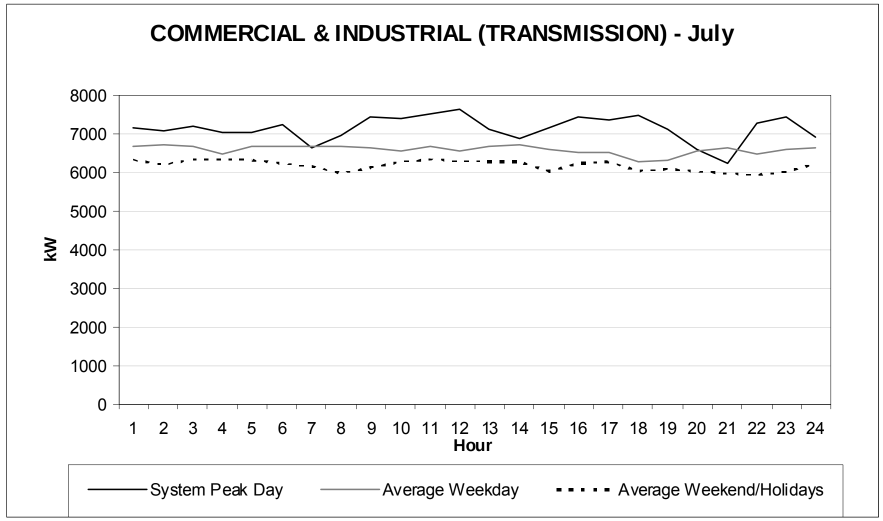


Figure 2.7-44 Commercial & Industrial (Transmission) August

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5388.4627	6332.9519	5854.2396
2	5520.6630	6274.6673	5918.1671
3	5510.3232	6295.4056	5774.3519
4	5417.8788	6212.4643	5868.0682
5	5479.4191	6180.4263	5769.9192
6	5422.8116	6126.2667	5768.6867
7	5526.2713	6211.5729	5817.3029
8	5631.2647	6193.0306	5605.4361
9	5637.4158	6136.2704	5636.0966
10	5723.5528	6015.0504	5453.8235
11	5666.1213	6143.5910	5546.6905
12	5673.1557	6311.2446	5564.4416
13	5735.5312	6439.9817	5690.2689
14	5653.7877	6497.1906	5768.7884
15	5557.2283	6465.7623	5407.8547
16	5749.1738	6263.2959	5329.0739
17	5393.5174	6267.2273	5282.5908
18	5325.1329	5965.8661	5470.4620
19	5285.7257	6000.5102	5209.9956
20	5381.9486	5980.8457	5505.2502
21	5399.7302	5953.1009	5681.1194
22	5515.5907	6198.4301	5766.5372
23	5336.7293	6311.0379	5767.6825
24	5189.1887	6208.6473	5846.2150

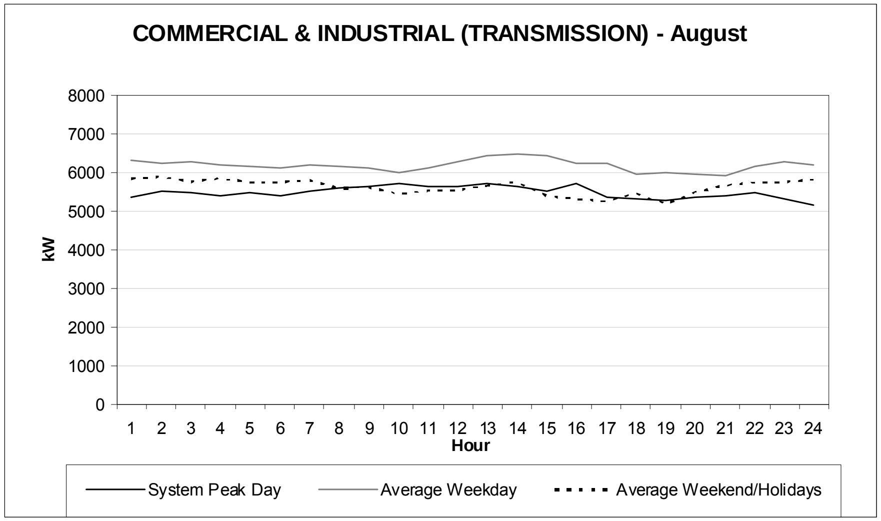


Figure 2.7-45 Commercial & Industrial (Transmission) September

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6804.8080	6373.1355	6088.9328
2	6562.0036	6475.3815	6164.6286
3	6821.9803	6371.2384	5900.5138
4	6428.0282	6216.6431	6303.0422
5	6711.5576	6421.9982	6091.9165
6	6817.4900	6363.2769	6043.9801
7	6436.5799	6296.4335	5728.1170
8	6839.5363	6270.8687	5821.9438
9	7038.9473	6184.1517	5881.1004
10	6757.7389	6211.3787	5753.8883
11	6841.9192	6308.1149	6004.3836
12	7259.6978	6374.3884	5658.3362
13	6393.3429	6428.9764	5917.2361
14	6923.1780	6543.1654	5622.6283
15	7284.1297	6559.3243	6004.7166
16	7273.0842	6533.7394	6125.2224
17	6962.8778	6563.8777	6040.0993
18	6488.9440	6490.5039	5860.7237
19	5602.7521	6302.1821	5794.3354
20	6286.2768	6247.8034	5733.3852
21	7030.6227	6392.1934	5970.5556
22	6980.7875	6414.3642	6040.7134
23	6426.1244	6448.1629	5810.1613
24	6657.5649	6429.7212	5844.5301

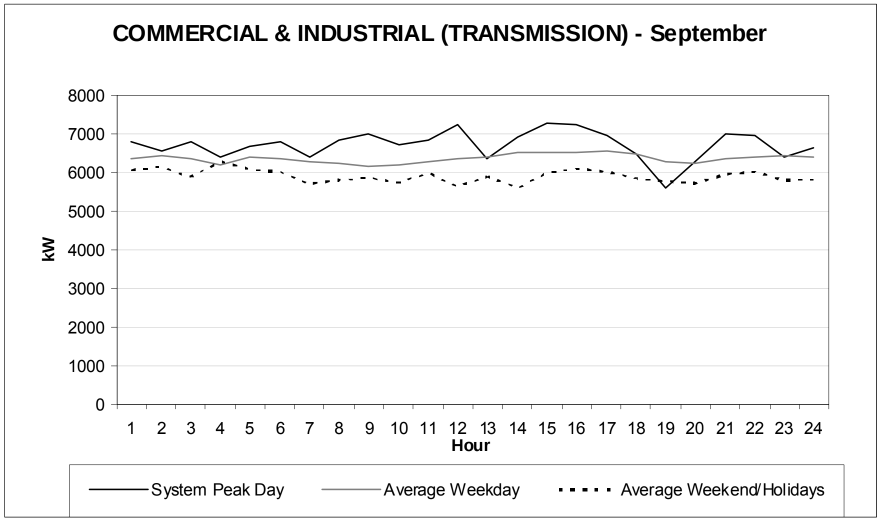


Figure 2.7-46 Commercial & Industrial (Transmission) October

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6615.0475	6642.3626	6082.2475
2	7046.0878	6603.8205	6174.4967
3	7172.8995	6705.3069	6058.8860
4	5898.6672	6603.7089	6107.4479
5	5569.1053	6635.7150	6071.8881
6	5500.3565	6589.6379	6069.6914
7	5641.5640	6472.3760	6036.7368
8	5677.3779	6444.6850	6013.6673
9	6475.7711	6267.5124	5960.0684
10	7172.2736	6322.2037	5775.0086
11	7136.0452	6518.4476	5772.3741
12	7158.6515	6679.5055	5937.4693
13	7176.4172	6626.5614	5881.3728
14	6572.4395	6662.1605	5834.7531
15	7113.5619	6725.5466	5747.1985
16	7411.3650	6755.4894	5872.4971
17	7276.5590	6642.5948	5832.4137
18	6777.9214	6556.4551	5846.1755
19	6836.6133	6386.5271	5727.6716
20	7012.7571	6383.1303	5789.6222
21	7143.7698	6682.4244	5906.6359
22	6639.0909	6688.3013	5815.4222
23	6864.4447	6795.2471	5873.9142
24	7008.8437	6753.8476	5960.8190

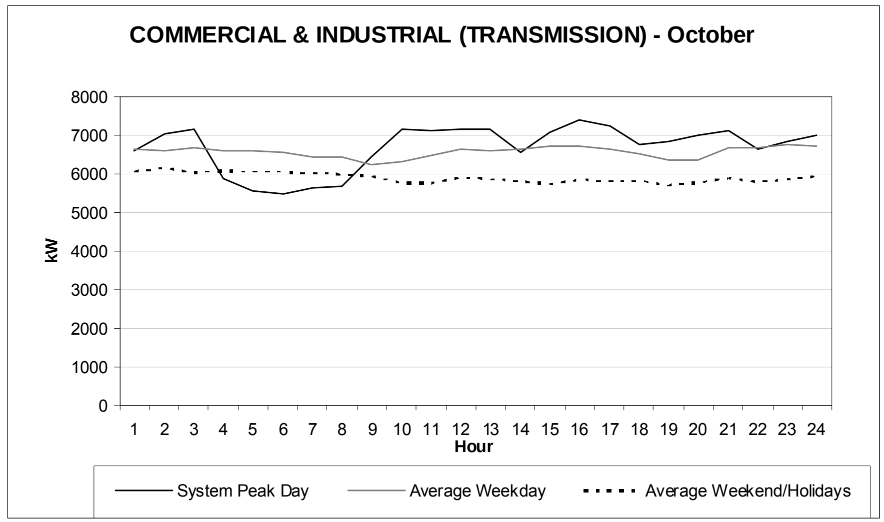


Figure 2.7-47 Commercial & Industrial (Transmission) November

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6212.0693	6347.3963	6130.5225
2	5489.3702	6442.2855	6293.6941
3	5205.0260	6521.2910	5791.4258
4	5919.0229	6612.9562	5806.7204
5	6253.5515	6465.7616	6023.6297
6	6347.9542	6493.4139	6069.9620
7	6301.8081	6433.4496	5798.5902
8	6506.1470	6483.7276	5546.9017
9	6699.2837	6414.0107	5761.8501
10	6306.5211	6370.8807	5505.5587
11	5040.3405	6246.9848	5417.2761
12	6541.8882	6297.1584	5525.5697
13	6674.8050	6367.6554	5734.4389
14	6663.1270	6372.9944	5671.3998
15	6306.6290	6436.3588	5691.7117
16	6631.4418	6616.4931	5887.8594
17	6885.0556	6560.2841	5808.5589
18	6783.0746	6451.4167	5822.8250
19	6953.6514	6421.6904	5484.7306
20	6701.5203	6478.7239	5621.9813
21	7188.5593	6499.0677	5479.4224
22	7356.6745	6709.9965	5627.2407
23	7084.6003	6571.8087	5746.5200
24	7063.9209	6456.7992	5767.9560

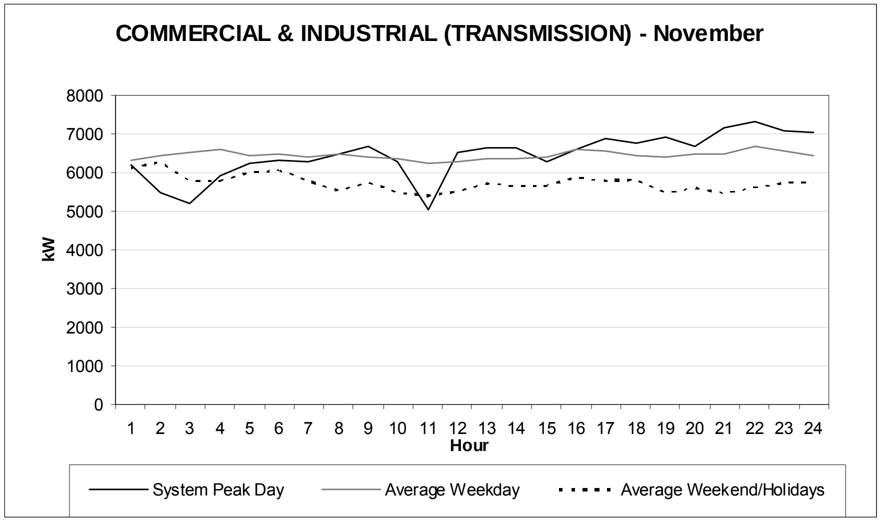


Figure 2.7-48 Commercial & Industrial (Transmission) December

COMMERCIAL & INDUSTRIAL (TRANSMISSION) DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7132.6739	7395.3917	6564.2458
2	7209.4499	7357.7137	6578.6292
3	7095.8812	7309.0692	6642.2024
4	7012.1958	7254.2763	6536.7923
5	6906.8412	7372.8648	6718.2586
6	7370.1066	7313.1429	6706.5339
7	7075.8812	7316.6530	6550.7262
8	7199.1877	7259.6755	6365.7381
9	7479.2678	7318.4036	6561.0023
10	6786.2892	7322.6910	6245.9979
11	6782.0338	7446.2411	6177.0708
12	7168.4757	7336.1446	6430.8194
13	6842.2662	7525.1778	6407.6386
14	7185.3565	7433.1299	6278.3882
15	6993.6891	7448.5030	6239.1872
16	7191.8881	7425.1664	6314.6241
17	6911.6314	7226.5841	6403.5148
18	6568.9785	7005.8082	6249.8382
19	6986.9158	7007.0493	6284.1037
20	7100.5070	7033.2387	6231.0152
21	6865.4666	7071.0412	6097.0198
22	6826.7515	7078.6803	6379.8995
23	6997.6732	7141.6123	6445.7183
24	7136.5021	7344.9443	6416.6536

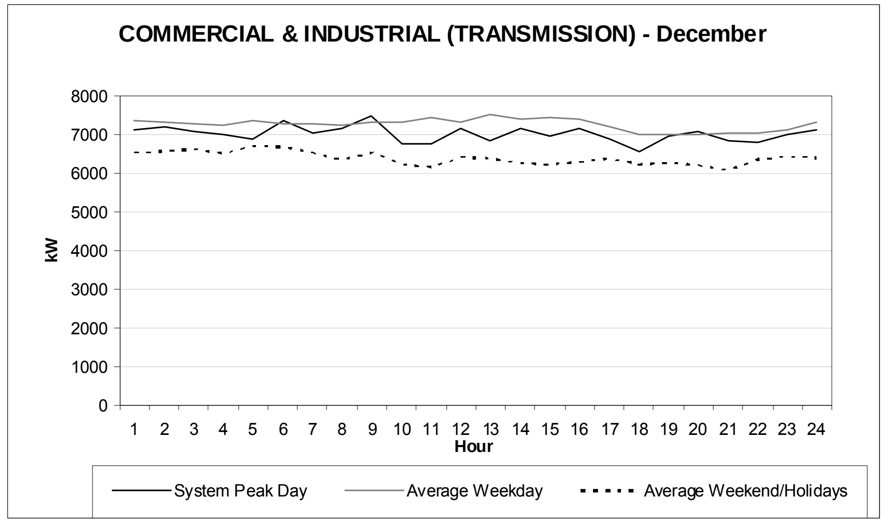


Figure 2.7-49 FERC Jurisdictional January

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	70068	62936	65069
2	69265	61847	63175
3	69278	61534	62487
4	69377	61898	62161
5	70883	63455	62766
6	75059	67791	64372
7	82172	74962	67425
8	85219	78467	71481
9	84553	78023	75247
10	83571	76723	76795
11	81974	75572	76538
12	80435	73941	75323
13	78010	71927	73622
14	76705	70658	72056
15	76497	70333	71364
16	77041	70636	71657
17	82140	74164	75246
18	94442	84397	85477
19	98348	88024	88305
20	97425	86840	86681
21	95314	84642	84362
22	90084	79794	80118
23	82908	72268	73337
24	76593	66071	67282

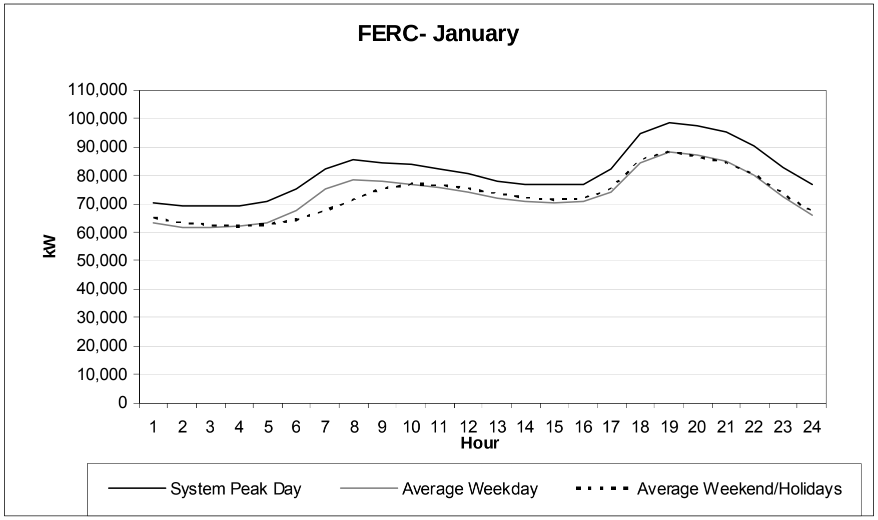


Figure 2.7-50 FERC Jurisdictional February

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	59529	62054	61670
2	59163	61148	60095
3	59433	61151	59658
4	59871	61684	59684
5	61734	63442	60239
6	65665	67888	62150
7	73071	74953	65534
8	77044	77476	69541
9	77957	77073	73996
10	78332	76029	75851
11	77168	74378	75308
12	75807	72684	74412
13	74171	70908	73225
14	73735	69639	72361
15	73534	69260	72461
16	74576	69590	72910
17	77103	71906	74947
18	85271	79317	80892
19	91362	85933	85684
20	89224	85088	83986
21	86744	83071	81837
22	81460	78241	77481
23	72694	70801	70877
24	66062	64854	64967

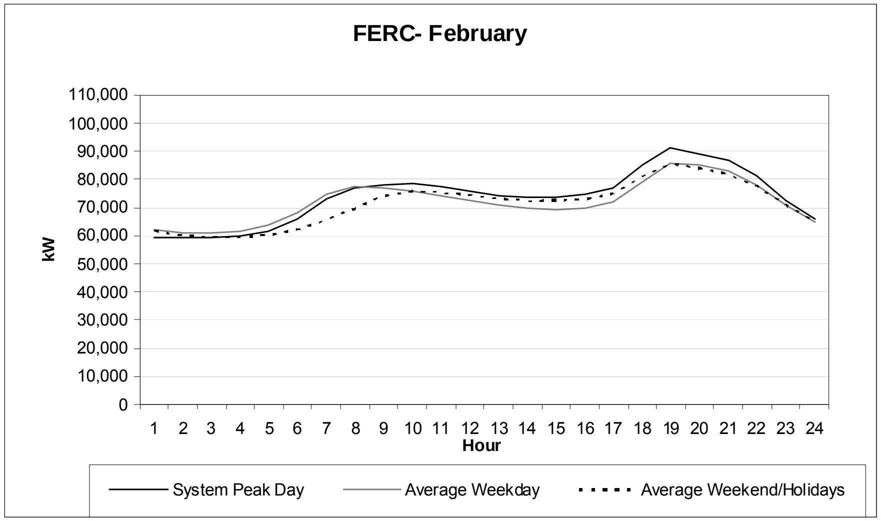


Figure 2.7-51 FERC Jurisdictional March

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	53596	54749	58525
2	52033	53543	56982
3	51470	53330	57293
4	51754	53754	56731
5	53142	55321	57376
6	57410	59430	59388
7	65110	65957	62473
8	68928	68919	65640
9	71046	69118	68747
10	71909	68837	69960
11	71930	67867	69470
12	72394	66711	68356
13	72385	65240	67113
14	71747	64402	65976
15	70648	63785	65225
16	70818	63581	64668
17	72942	64340	65333
18	78246	67459	67997
19	83553	72225	71637
20	81473	75192	74744
21	77920	75190	75428
22	72053	71242	71883
23	63880	64356	65469
24	57694	58299	59678

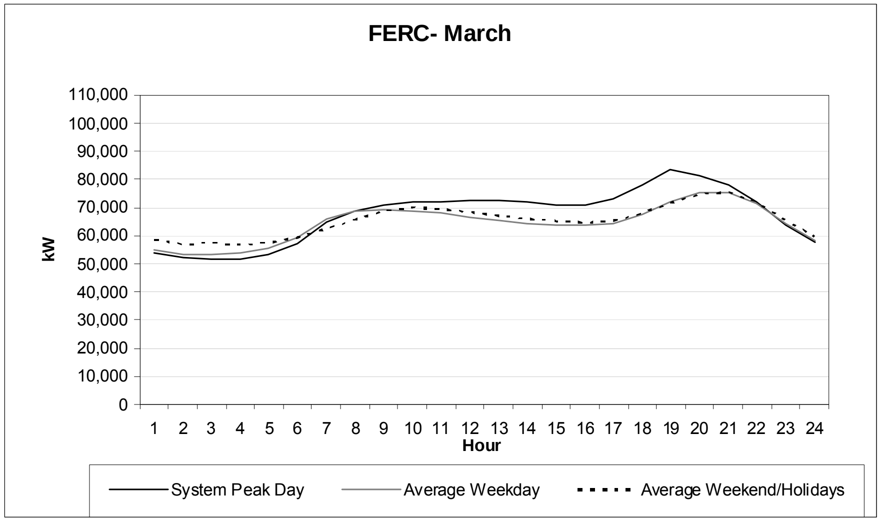


Figure 2.7-52 FERC Jurisdictional April

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	50514	47686	50140
2	49791	46506	48424
3	47991	46214	47902
4	48159	46383	47795
5	50118	47814	48450
6	54432	51613	50049
7	62200	57791	52672
8	65821	60243	55786
9	67059	60616	59292
10	68216	60526	61001
11	68413	60072	60739
12	68255	59278	59913
13	67445	58502	58834
14	67524	58036	57604
15	66561	57588	56826
16	66831	57239	56532
17	68135	57592	57098
18	70535	59134	58306
19	73157	60499	59331
20	75810	63068	62457
21	77260	66434	65503
22	72667	63595	62922
23	64828	56972	57185
24	58435	51243	51707

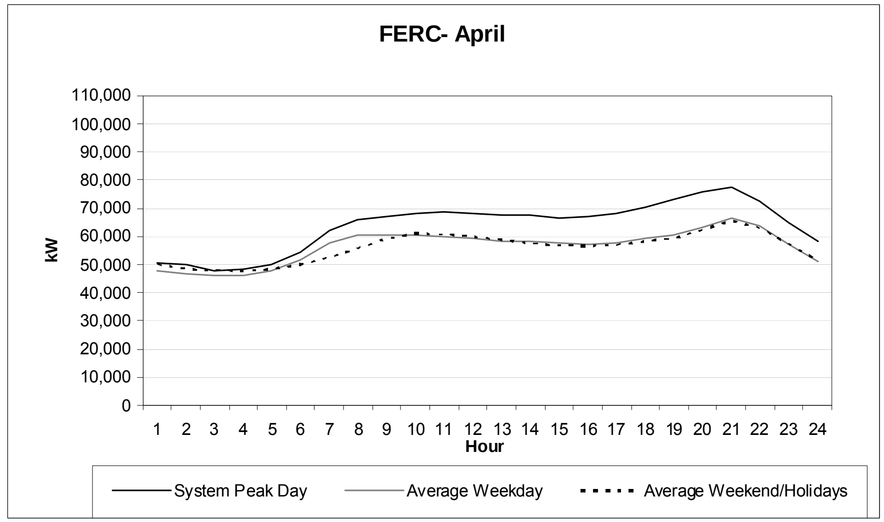


Figure 2.7-53 FERC Jurisdictional May

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	47385	45094	47298
2	44707	43644	45437
3	43194	43015	44677
4	42343	43137	44489
5	43004	44240	44828
6	45414	47525	45772
7	49671	52484	47138
8	54537	55460	50525
9	57896	56015	54320
10	61066	56060	56462
11	64037	56418	57035
12	66483	56458	56769
13	67938	56338	56353
14	69020	56167	55508
15	69451	56068	55418
16	69936	56049	55546
17	72436	57127	56610
18	74202	58352	57793
19	73314	59107	58219
20	70576	59898	58412
21	71395	63103	61557
22	70251	61818	60689
23	63392	55081	54969
24	56011	48966	49128

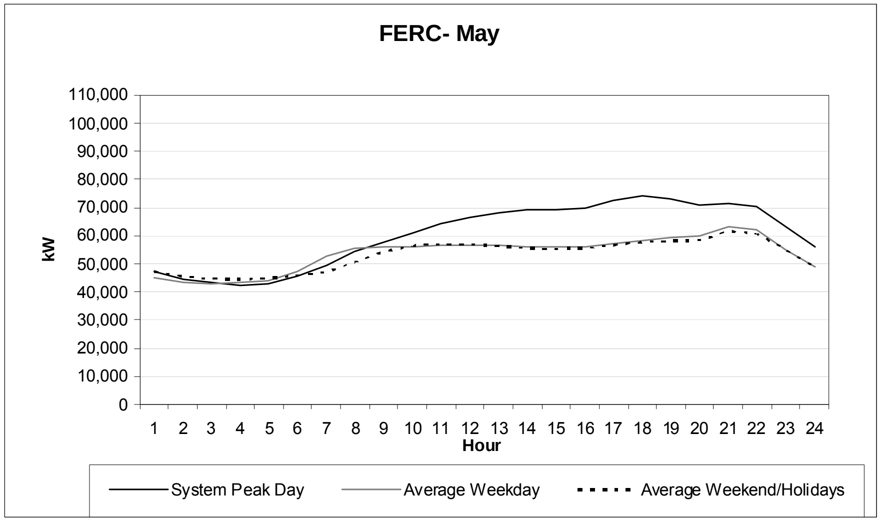


Figure 2.7-54 FERC Jurisdictional June

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	50834	48026	49672
2	47739	45186	46181
3	45210	43666	44571
4	44654	42984	43839
5	45083	43395	43665
6	46449	45461	44140
7	49575	48793	45368
8	54397	53182	48723
9	58821	56690	53702
10	62878	59081	57594
11	67249	61177	60262
12	70909	63011	61907
13	74143	64267	63353
14	77562	65894	64839
15	80116	67765	66004
16	82150	69719	67252
17	84207	71634	68738
18	86199	72943	69616
19	85061	72707	68018
20	81877	70966	66141
21	79966	70529	66141
22	77376	69877	65974
23	67634	62274	59817
24	58103	54143	52940

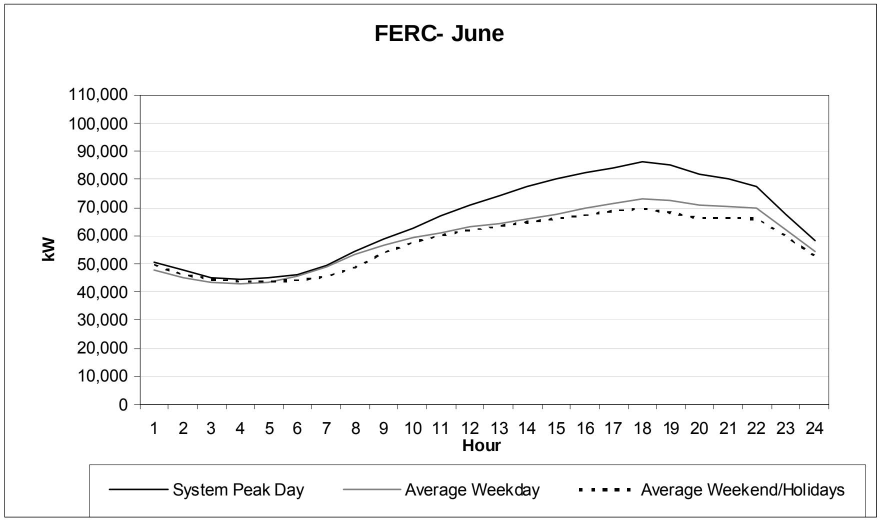


Figure 2.7-55 FERC Jurisdictional July

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	53421	50850	51926
2	49202	47394	48376
3	46730	45361	46120
4	45719	44237	44827
5	45738	44399	44406
6	47852	46477	44962
7	51559	49899	46068
8	57266	54911	49527
9	61887	59489	54973
10	64418	63168	59803
11	67845	66657	63526
12	75076	69651	66164
13	78541	72130	68569
14	81775	74597	70696
15	84867	76148	72771
16	87722	77120	74560
17	89407	78512	75663
18	87692	79779	76877
19	84604	79215	75862
20	79249	76770	73109
21	76712	75748	71997
22	75251	74064	70752
23	66730	65941	63863
24	57584	57346	56244

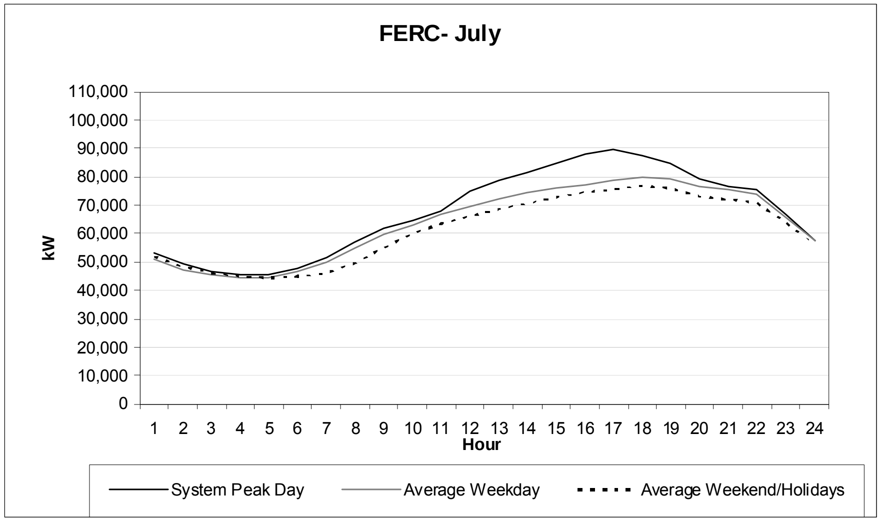


Figure 2.7-56 FERC Jurisdictional August

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	48476	48595	50962
2	45129	45500	47633
3	43390	43492	45819
4	42493	42703	44842
5	43026	43170	44497
6	45795	45951	45441
7	51063	50658	46461
8	56118	54848	49183
9	60271	58276	54962
10	63752	61106	59905
11	67638	63721	63948
12	71256	65915	67197
13	75137	67914	69931
14	78716	70125	72624
15	81749	72310	75116
16	84599	73801	77332
17	85549	75277	78743
18	86535	76423	79303
19	86270	75767	78336
20	83846	73854	75729
21	83773	74361	75490
22	77970	70383	71684
23	67512	61743	63468
24	58074	53628	55540

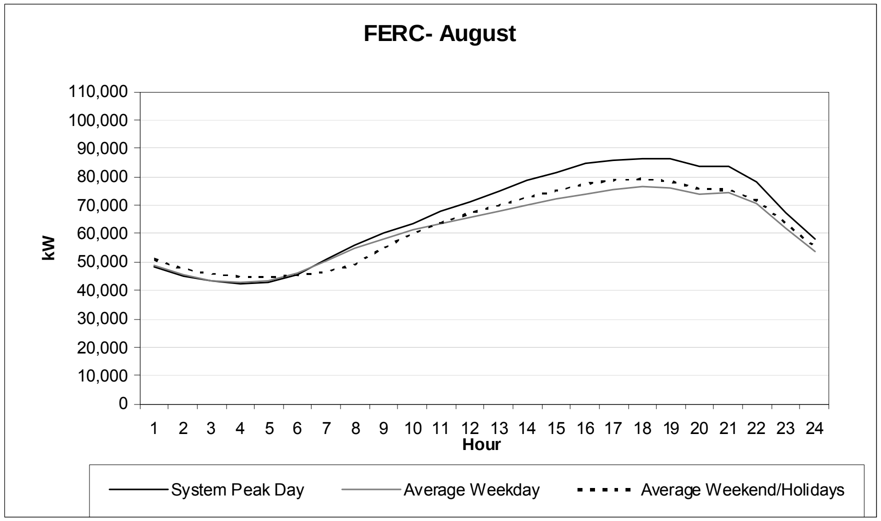


Figure 2.7-57 FERC Jurisdictional September

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	44516	45436	46936
2	42474	43075	44295
3	41033	41538	43197
4	40694	41153	42738
5	41424	41927	42689
6	44728	45246	43995
7	50662	51590	45749
8	53656	54442	47986
9	55651	55603	52317
10	57435	56541	55334
11	59205	57752	57195
12	60688	58715	58412
13	62032	59616	59611
14	63884	61030	61129
15	65925	62500	63017
16	68055	64026	65560
17	70361	65997	67769
18	71995	67699	69443
19	72267	67951	69397
20	73358	69844	70474
21	72788	69639	69653
22	67022	64436	64719
23	58081	56590	57434
24	50545	49443	50540

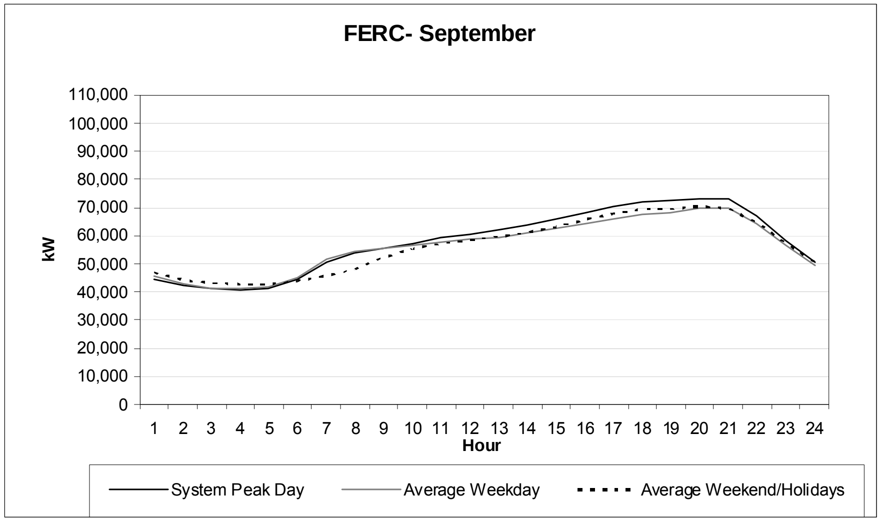


Figure 2.7-58 FERC Jurisdictional October

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	41039	44069	45193
2	39362	42513	43696
3	38796	41769	42963
4	38746	41782	42450
5	39585	42870	42792
6	43244	46648	44187
7	50134	53724	46852
8	52751	56964	49272
9	52676	56574	52689
10	53013	56328	54495
11	53440	56215	54970
12	54628	55959	54722
13	54913	55483	54329
14	55476	55294	53916
15	56041	55160	53864
16	56919	55050	54316
17	58181	55806	55522
18	59342	58013	57848
19	62603	63022	61982
20	66465	65933	63908
21	64941	64408	62282
22	60304	60074	58353
23	53193	53517	52374
24	47082	47863	46958

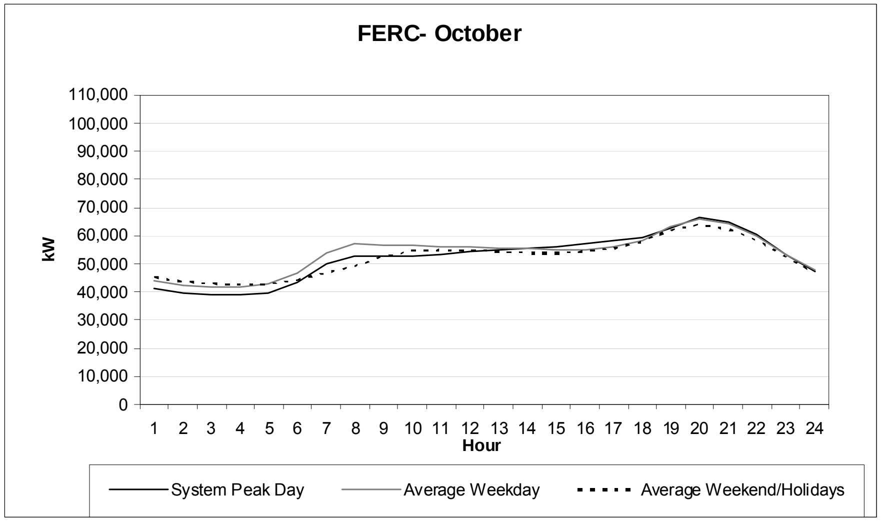


Figure 2.7-59 FERC Jurisdictional November

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	61919	54938	57440
2	60654	54132	55970
3	60451	54090	55520
4	60825	54586	55545
5	62790	56248	56353
6	67687	60662	58275
7	75564	67645	61451
8	77918	69698	64500
9	77240	68501	67007
10	76888	67230	67836
11	76839	66016	67328
12	76775	64825	66436
13	76854	63807	65507
14	76569	63127	64460
15	76633	62892	64319
16	77845	63566	65283
17	82304	67090	69335
18	90809	74450	76216
19	92558	77402	77405
20	91222	76812	76242
21	88661	74732	74470
22	82994	70334	70384
23	74951	63898	64594
24	68964	58560	59628

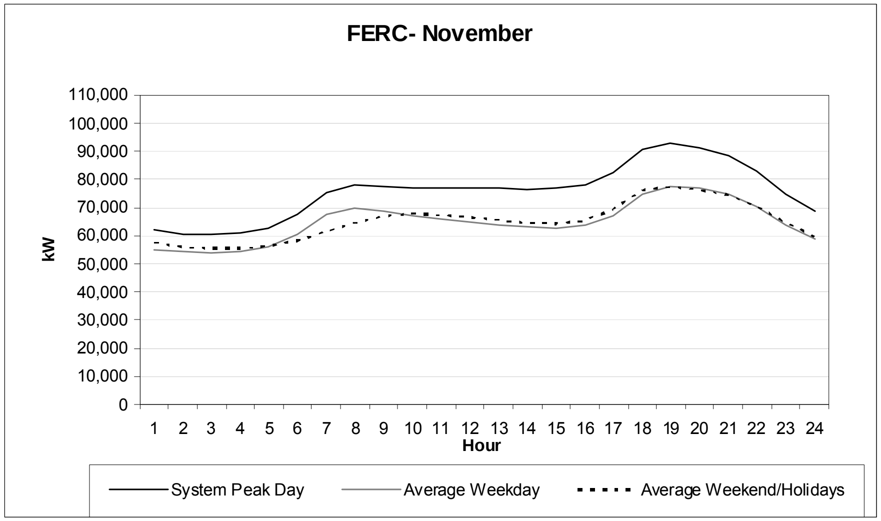
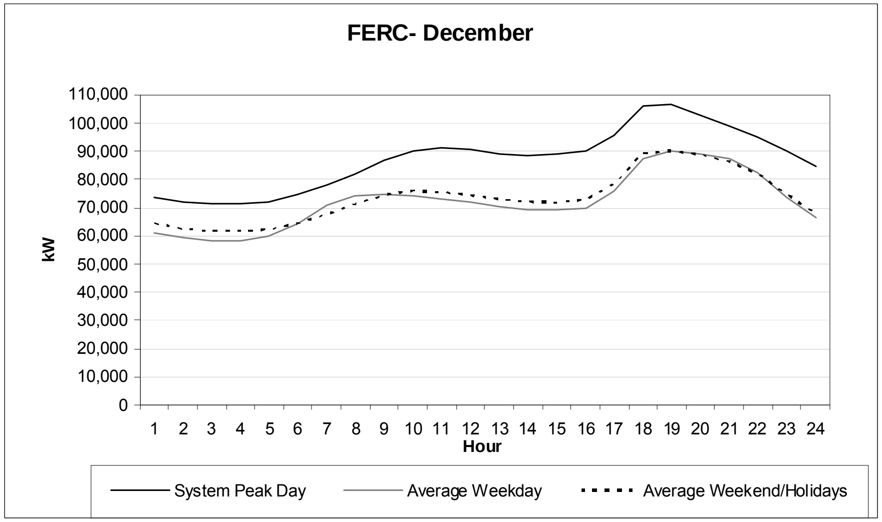


Figure 2.7-60 FERC Jurisdictional December

FERC DAILY LOAD PROFILES

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	73533	61173	64459
2	72174	59269	62389
3	71628	58421	61717
4	71284	58436	61647
5	71935	59929	62243
6	74835	64079	64371
7	78099	70728	67622
8	81936	74287	71188
9	86787	74570	74476
10	90124	74097	75961
11	91081	73008	75493
12	90507	71748	74305
13	89251	70330	72938
14	88610	69406	72075
15	89000	69097	71853
16	90288	70000	72707
17	95474	76079	78369
18	106085	87620	89216
19	106325	89850	90164
20	102750	89103	88731
21	99109	87228	86367
22	95141	82179	81980
23	89838	73741	74833
24	84568	66169	67802



2.8 PHASE 1 PLAN DEVELOPMENT AND MODELING DETAILS

Strategist Model Description

Public Service used the Strategist electric utility planning model to represent the various costs of the Least-Cost Baseline Case and all alternative plans discussed in Volume 1 of this 2011 ERP.

Strategist is a computer based model specifically designed to represent the many characteristics of an electric utility's power supply system and to simulate economic dispatch of the generating resources in that system to meet customer demand for electric power (a.k.a., load) in the lowest cost manner. The model also has the capability to determine the least-cost mix of generation resources that should be added to an electric system to help serve future load growth. Public Service has used Strategist in developing its last three electric resource plans submitted to the Commission.

Strategist incorporates a wide range of variables that can be used to represent various types of electric generating facilities, e.g. coal, gas, wind, solar and storage facilities. Strategist contains four basic modules ("LFA," "GAF," "CER," "PROVIEW") that work in concert to simulate the operation of the existing units as well as the new units that are added to the system in future years to meet load growth. The model tracks and reports capital costs (and the associated revenue requirements), operations and maintenance costs, fuel costs, emissions and associated costs, integration costs for solar and wind and coal cycling costs.

Organization of Section 2.8

The plan development and Strategist modeling is composed of three primary functions. The three functions and the subsets of those functions (and the remaining Section 2.8 subsections) are as follows:

1) Strategist Modeling - Set-Up and Function
    a) Demand and Energy Forecasts
    b) Modeling of the Existing Public Service System
    c) Use of generics to Meet Future Resource Need
2) Modeling the Alternative Plans
    a) Development and Results of the Least-Cost Baseline Case
    b) Development of the Alternative Plans
3) Modeling Results
    a) Results for the Alternative Plans
    b) Sensitivity Analyses for the Alternative Plans

Section 2.8 is a very long section. We believe that Section 2.8 requires additional indication to the reader as to the topic being discussed in the various portions of this section. To aid the reader in this regard, within the header for each page of Section 2.8, the particular subsection being discussed is listed, e.g. "Strategist Modeling – Set-up and Function."

1. Strategist Modeling - Set-Up and Function

The set-up process and function of the Strategist model for construction of the "at least three alternate plans" required by ERP Rule 3604(k) is described in the following three subsections:

a) Demand and Energy Forecasts
b) Modeling of the Existing Public Service System
c) Use of generics to Meet Future Resource Need

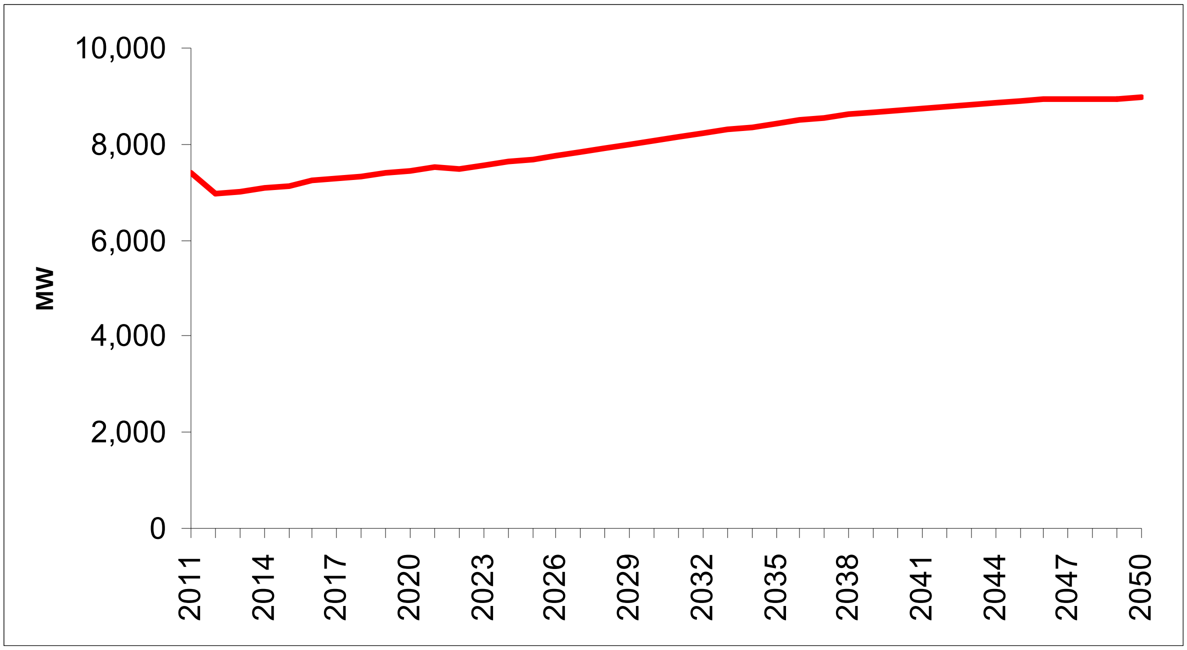
a. Demand and Energy Forecasts

Along with existing generation resources, the demand and energy forecasts drive the type and number of resources needed in the future. Embedded within the long term forecasts are demand and energy savings consistent with those approved by the Commission in the DSM Docket No. 10A-554EG with modifications proposed by the Company for consideration in resource acquisition and a forecast of demand response programs.[21]

The demand forecast is increased by the planning reserve margin to provide for load and generation contingencies. This "load + reserve margin" result is used in determining the need for additional generating resources. Attachment 2.11-1 shows a Load and Resources table detailing how much generation capacity is available and required per year during the RAP. Figure 2.8-1 plots the annual generation capacity requirements for the entire Planning Period represented by the firm load plus increased 16.3%. The energy forecast in conjunction with the demand forecast also informs what types of resources would make up a well balanced portfolio, i.e., a balanced mix of baseload energy, intermediate and peaking generation.

[21] A detailed description of how the demand and energy forecasts are developed is included in Section 2.6.

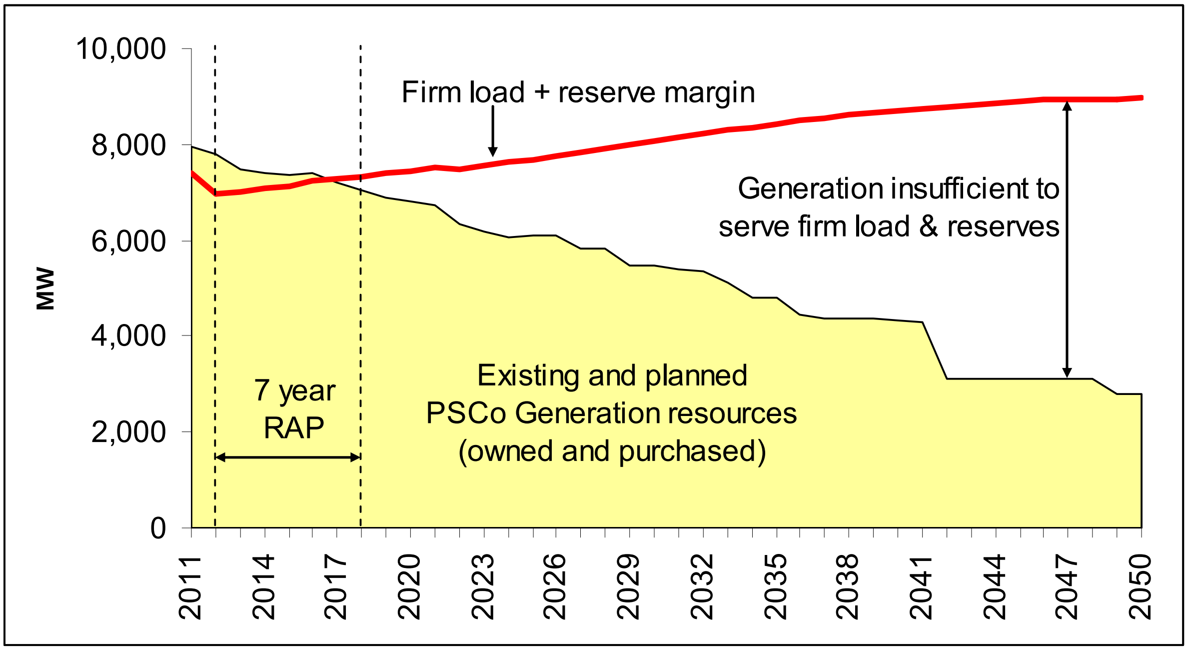
Figure 2.8-1 Firm Obligation Load and Reserve Margin



b. Modeling the Existing Public Service Electric System

Public Service constructed a representation of its electric supply system in the Strategist model that reflected the existing and planned generation portfolio (owned and purchased) including planned 2007 ERP and CACJA actions. The model also includes the proposed 200 MW Limon II wind facility currently before the Commission for approval. Figure 2.8-2 shows the net dependable generation capacity ("NDC") of the Public Service electric system and how it diminishes over time as a result of increasing firm obligation load ("FOL"), expiring PPAs, and Company-owned generation resource retirements. The gap between the yellow area and the red line between years 2017 and 2050 represents the amount of additional generation capacity needed in future years.

Figure 2.8-2 NDC and FOL w/ Reserve Margin



Each existing resource that makes up the yellow in Figure 2.8-2 is modeled separately in Strategist and includes both operational characteristics and costs of operation. The operational characteristics and costs allow the model to not only estimate the fixed costs of they system, e.g., fixed O&M, capacity payments to IPPs etc., but also allows it to dispatch the system in the most economic manner to meet energy requirements. The assumptions in Attachment 2.8-1, included at the end of this section, include the information that goes into modeling each type of existing resource.

Cherokee 4 and Arapahoe 4

In development of the alternative plans in Phase 1, Cherokee 4 and Arapahoe 4 are assumed to operate on gas through 2028 and 2023 respectively. Arapahoe 4 is assumed to operate on gas as a peaking unit from 2014-2023. Cherokee 4 is assumed to operate on gas as a peaking unit from 2018-2028. The Company describes in Section 2.9 the process by which it will present alternatives to running Arapahoe 4 and Cherokee 4 on natural gas as directed in Commission Decision No. C10-1328.

Cabin Creek

Cabin Creek provides a number of significant benefits to the reliable and cost-effective operation of the electric system including quick start capability (less than 10 minute to full capacity), fast ramp rate, multiple starts/stops capability without maintenance penalty, and valuable regulation and spinning reserves capability (either pumping or generating mode). The current Federal Energy Regulatory Commission license to operate Cabin Creek expires in February 2014 and Public Service is in the process of preparing the final relicense application due in February 2012. Public Service plans to relicense the facility for an additional 30-40 years of operation. As part of the relicensing effort, Public Service is investigating the feasibility of upgrading the Cabin Creek facility and improving its operational efficiency and capacity. Until these upgrades are fully studied however, Cabin Creek will continue to be reflected at its current rating in the alternative plan analyses through the planning period.

c. Use of Generics to Meet Future Resource Need

Figure 2.8-2 shows that there are insufficient resources in the future to meet firm obligation load and reserve margin requirements. Therefore, in addition to modeling the existing electric system, generic resources are added to the model to serve future firm obligation load and to maintain an acceptable planning reserve margin as well as to meet energy needs in a cost effective manner. The cost and performance information for the generic resources included in the alternative plans are summarized in Tables 2.8-1 and 2.8-2. Projected emissions and emissions rates for the generic resources are provided in Attachment 2.8-2 per Commission Rule 3604(g).

Table 2.8-1 Generic Dispatchable Resource Cost and Performance

	RAP Generic Resources				Post-RAP Generic Resources			
Dispatchable Resources [1,2]	**2x1 Combined Cycle [3]**	**1x1 Combined Cycle [4]**	**Combustion Turbine [5]**	**Battery[6]**	**Baseload Plant[7]**	**2x1 Combined Cycle [8]**	**1x1 Combined Cycle [9]**	**Combustion Turbine [10]**
Nameplate Capacity (MW)	808	346	214	25	511	780	335	214
Summer Duct Firing Capacity (MW)	128	63	N/A	N/A	N/A	121	62	N/A
Summer Peak Capacity with ducts (MW)	658	315	173	25	485	643	310	173
Cooling	Wet	Wet	N/A	N/A	Dry	Dry	Dry	N/A
Capital Cost ($/kW)[11]	$713	$1,181	$655	$3,000	$5,013	$783	$1,273	$655
Electric Transmission Delivery ($/kW-yr)[12]	$28	$0	$0	$0	$28	$28	$0	$0
Gas Demand ($000/yr)[13]	$4,800	$2,400	$0	$0	N/A	$4,800	$2,400	$0
Book Life	45	45	40	15	60	45	45	40
Fixed O&M Cost ($000/yr)	$5,777	$3,861	$886	$0	$20,859	$5,777	$3,861	$496
Variable O&M Cost ($/MWh)	$2.37	$2.43	$10.43	$0.00	$9.59	$1.65	$1.74	$10.43
Ongoing Capital Expenditures ($000/yr)	$3,386	$1,903	$1,343	$0	$12,528	$3,386	$1,902	$1,343
Heat Rate with Duct Firing (btu/kWh)[14]	7,173	7042	N/A	N/A	N/A	7,469	7253	N/A
Heat Rate 100 % Loading (btu/kWh)	6,947	6,733	10,596	N/A	13,022	7,143	6878	10596
Heat Rate ~75 % Loading (btu/kWh)	7,014	7021	11,207	N/A	13,535	7,190	7200	11207
Heat Rate ~50 % Loading (btu/kWh)	7,135	7,277	12,769	N/A	14,685	7,239	7478	12769
Heat Rate ~30 % Loading (btu/kWh)	7,849	N/A	N/A	N/A	18,585	7,720	N/A	N/A
Forced Outage Rate	3%	3%	3%	0%	6%	3%	3%	3%
Maintenance (wks/yr)	2	2	0.5	0.0	4	2	2	0.5
Typical Capacity Factor	37%	37%	9%	N/A	85%	37%	37%	9%
CO2 Emissions (lbs/MMBtu)	118	118	118	N/A	22	118	118	118
Water Consumption (acre-ft/yr)	4,125	26	12	N/A	985	29	13	12
Turnaround Efficiency	N/A	N/A	N/A	75%	N/A	N/A	N/A	N/A
Storage Capability (MWh)	N/A	N/A	N/A	180	N/A	N/A	N/A	N/A

Notes:

(1) All costs in year 2011 dollars

(2) Thermal unit cost and performance characteris ics are from Xcel Energy Services and other sources such as CERA, EPRI and EIA.

(3) Based on a Siemens 5000F 2x1 wet cooled combined cycle. Estimates are based on a greenfield facility wi h an EPC contract. A brownfield location would have about 15% less capital costs and 40% less Fixed O&M. Brownfield estimates are estimated by removing certain cost items from the greenfield estimate but costs for an actual brownfield facility are very site specific. Heat rate values are all based on the estimated facility performance under annual average ambient conditions.

(4) Based on a GE 7FA 1x1 wet cooled combined cycle. Estimates are based on a greenfield facility with an EPC contract. A brownfield location would have about 25% less capital costs and 25% less Fixed O&M. Brownfield estimates are estimated by removing certain cost items from the greenfield estimate but costs for an actual brownfield facility are very site specific. Heat rate values are all based on the estimated facility performance under annual average ambient conditions.

(5) Based on a Siemens 5000F combustion turbine. CTs are generally constructed in pairs to take advantage of economies of scale. A two unit project is projected to cost 170% of a one unit project. Summer capacity MWs do not include duct or supplemental firing. Estimates are based on a greenfield facility with an EPC contract. A brownfield location would have about 25% less capital costs and 50% less Fixed O&M. Brownfield estimates are estimated by removing certain cost items from the greenfield estimate but costs for an actual brownfield facility are very site specific. Heat rates values are based on summer ratings. Water consumption rates are based on the assumption hat the unit would operate on fuel oil for 10% of the operating hours.

(6) Based on a sodium sulfur battery. Source: EPRI Electricity Energy Storage Technology Options (1020676)

(7) Baseload plant based on a dry cooled supercritical pulverized coal plant with 90% carbon capture and sequestration

(8) Based on a Siemens 5000F 2x1 dry cooled combined cycle. Estimates are based on a greenfield facility with an EPC contract. Heat rate values are all based on the estimated facility performance under annual average ambient condi ions.

(9) Based on a GE 7FA 1x1 dry cooled combined cycle. Estimates are based on a greenfield facility. Heat rate values are all based on the estimated facility performance under annual average ambient condi ions.

(10) Based on a Siemens 5000F combustion turbine. Summer capacity MWs do not include duct or supplemental firing. Es imates are based on a greenfield facility with an assumption that manpower could be shared with another resource. Heat rates values are based on summer ratings.

(11) Interconnection and onsite gas supply costs included in construction costs. The Capital Cost value is based on the estimated project cost divided by the nameplate rating.

(12) Resources less than 500 MW are assumed to be built in locations with sufficient existing transmission capability. The Baseload and 2x1 combined cycle plants are assigned prorated transmission upgrade costs based on SB100 project estimated costs for Missile Site, Midway-Waterton and Smoky Hill SB100 projects.

(13) Generic combustion turbine has dual fuel capability and was assigned a gas demand charge.

(14) Heat rate improvements are included in the modeling evaluation (5% improvement in heat rate every 10 years).

Baseload Plant Description

The generic baseload plant is meant to represent a resource that is high in capital costs but low in energy costs and could represent nuclear, coal with carbon capture with sequestration, IGCC with sequestration or some other technology that may become available in the future to meet both baseload energy and capacity needs. The generic baseload plant's costs and operating characteristics are based on a supercritical pulverized coal plant with 90% CO_2 capture but could represent any low or no CO_2 emitting baseload type resource.

Combustion Turbine Description
Natural gas-fired combustion turbines are available in a range of sizes (25 MW to 300 MW). Combustion turbines typically have low capital costs, but are relatively inefficient sources of energy and thus have high operating costs ($/MWh). The typical role for combustion turbine is to be run only at times of the highest load demand (i.e. "peaking" capacity) and during unanticipated outages of lower cost generators.

Combined Cycle Description
Natural gas-fired combined cycle units incorporate single or multiple combustion turbines used in conjunction with a Heat Recovery Steam Generator. The waste heat from a combustion turbine's high temperature exhaust gas is captured and used to create steam to run a steam turbine for additional power and significantly higher efficiency, i.e., a lower heat rate, than a combustion turbine operating in simple cycle mode. Combined cycle units range in generation sizes and have higher capital costs than combustion turbine peaking units. A combined cycle's ideal role is to be operated in an "intermediate" role, which means less often than base load resources but more often than peaking resources. The generic combined cycle resources included in the evaluation included a 1x1 combined cycle plant (1 combustion turbine x 1 steam turbine) and a 2x1 combined cycle plant (2 combustion turbines x 1 steam turbine).

Battery Description
A battery is a form of energy and capacity storage that can be used to store low cost energy during a time of low load and use it during a peak period to displace high cost energy. Batteries are discussed in detail in Section 2.2. For the evaluation of alternative plans, batteries are considered a Section 123 Resource based on the current state of battery technologies. Storage resources are described in more detail in Section 2.2.

In the alternative plan modeling, wind integration costs are adjusted based on the amount of storage assumed to be on the system based upon results of the 2GW-3GW wind integration study.[22]

Table 2.8-2 Generic Renewable Resource Cost and Performance

Renewable Resources [1]	PTC Wind	Non PTC Wind	30% ITC Solar PV[2]	10% ITC Solar PV[2]	30% ITC Solar Thermal with storage[3]	10% ITC Solar Thermal with storage[3]	30% ITC Solar Thermal with storage[3]	10% ITC Solar Thermal with storage[3]
Nameplate Capacity (MW)	100	100	25	25	50	50	125	125
ELCC Capacity Credit (MW)	12.5	12.5	13.8	13.8	50	50	125	125
Book Life	25	25	20	20	25	25	25	25
Transmission Delivery ($/kW)[4]	$0	$0	$0	$0	$0	$0	$0	$0
Variable Cost ($/MWh)	$38	$68	$99	$130	$202	$253	$178	$223
Dispatchable	no	no	no	no	partial	partial	partial	partial
Forced Outage Rate [5]	0%	0%	0%	0%	0%	0%	0%	0%
Maintenance (wks/yr) [6]	0.0	0.0	0.0	0 0	0	0	0	0
Water Consumption (acre-ft/yr)	0.0	0.0	0.0	0 0	77	77	192	192
Typical Capacity Factor	48%	48%	30%	30%	38%	38%	38%	38%

Notes:

(1) All costs assume 2017 COD. Prices listed are levelized prices over the book life.

(2) Solar PV exhibits a declining cost curve. Solar assumed to be installed in 2018 is 3% less expensive than solar installed in 2017. Solar installed past 2018 assumed to have the same levelized price as that installed in 2018.

(3) Solar thermal with storage exhibits a declining cost curve. Solar assumed to be installed in 2018 is 3% less expensive than solar installed in 2017. Solar installed past 2018 is assumed to have the same levelized price as hat installed in 2018.

(4) Transmission delivery costs are not included in the generic resource estimates. It's assumed that the generic resources could be built on exis ing site locations which may minimize transmission delivery costs.

(5) Forced Outage Rates are included within the expected hourly energy pattern and reflected in the overall estimate of capacity factors.

(6) Maintenance is included within the expected hourly energy pattern and reflected in the overall estimate of capacity factors.

Wind Description

Public Service currently has 1,260 MW of utility scale wind generation on the system and it's expected that an additional 900 MW of wind will be operational on the Public Service system by the end of 2012. The Company has seen a significant drop in the price of wind in the past year. This coupled with the Production Tax Credit (currently scheduled to expire by 12/31/2012) has made wind an inexpensive resource relative to other renewable energy options. However, in the alternative plan evaluation, wind added after 12/31/2012 is assumed to be ineligible for a Production Tax Credit, which is consistent with current legislation.

Based on historical, turbine-height, wind velocity data from within its fleet of wind generators, the Company has developed Typical Wind Year ("TWY") proxy hourly annual wind velocity curves for northern ("Northern TWY) and southern ("Southern TWY") regions of Colorado. These proxy wind velocity curves can be applied to wind turbine curves to develop typical, hourly annual wind generation curves. For the alternative plans studied below, the Company

[22] See Attachment 2.13

employed a wind turbine curve represented by a GE 1.6-100 turbine.

Wind generation resources are added in 200 MW minimum increments; 100 MW of each 200 MW block is assigned a Northern TWY profile and the other 100 MW is assigned a Southern TWY profile.

Generic PTC-eligible wind pricing for the alternative plans was developed as a economic carrying charge representation of the revenue requirements for a $1925/kW (2011$) total installed cost, an assumption of 47.5% annual energy capacity factor, and a fixed O&M assumption of approximately $28/kW annually. The installed cost and the fixed O&M costs were assumed to inflate at 1.78% annually through the Planning Period. These cost and performance assumptions result in levelized energy costs consistent with PPA bids received in the Public Service 2011 Wind RFP.

Generic, non-PTC-eligible wind pricing was set equal to the PTC-eligible wind pricing with a $30/MWh adder for the economic value of the lost PTC. This $30/MWh adder is consistent with the level provided to the Company in prior wind RFPs that requested both PTC-eligible and non-PTC-eligible pricing.

In addition to the energy costs, wind resources added in the alternative plan evaluation are assigned wind integration costs based on the 2011 2 GW and 3 GW Wind Integration Cost Study[23] and coal cycling costs based on the 2011 Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment study.[24]

Solar PV Description

Photovoltaic cells employ a semiconductor material to directly convert sunlight to DC electricity; further conversion to AC electricity is required for grid-connected applications. PV systems are classified as flat plate or concentrating. Flat plate systems can track the sun in one or two axes or be fixed in place; concentrating systems must employ two-axis tracking. Concentrating PV systems require direct sunlight whereas flat plate systems can generate electricity from both direct and indirect sunlight. PV systems are easily sited, can be rapidly constructed, and can be readily expanded by adding additional arrays.

Given the fuel source, there are no emissions and only minimal amounts of water may be needed for array cleaning. However,

[23] See Attachment 2.13.
[24] See Attachment 2.12.

photovoltaic energy is non-dispatchable, highly intermittent on minute-scale and second-scale time frames, and the solar resource peaks at solar noon, which is typically two to four hours before system load peaks. For the alternative plan evaluations, the Company has assumed that incremental generators would consist of high-efficiency modules located in the San Luis Valley and would employ 1-axis tracking. Hourly generation profiles were derived from 2010 hourly generation meter data for several existing 1-axis systems in the San Luis Valley.

Solar projects installed on or before 12/31/2016 are eligible for an Investment Tax Credit ("ITC") equal to 30% of the investment cost; solar projects installed after 12/31/2016 are eligible for a 10% ITC. It is assumed in the alternative plan analyses that the PV additions in the RAP would meet the 12/31/2016 deadline and be eligible for a 30% ITC. PV pricing for the alternative plans was developed as the economic carrying charge representation of the revenue requirements for installed system costs consistent with market pricing from recent RFPs and Solar*Rewards installations forecasted to decline with the declining cost curves presented in the May 6, 2010 Deutsche Bank PV study.[25] Pricing for the post-RAP period, generic PV was set as the 30% ITC price curve for a 2108 install date in nominal dollar terms through the Planning Period.

In addition to the annual costs of energy for solar PV, a solar integration cost is assigned to solar in the evaluation of alternative plans. The solar integration costs are developed from the 2009 Solar Integration Study.[26]

Solar Thermal with Storage Description

One of the unique attributes of solar thermal generation vis-à-vis other solar sources is the ability to introduce thermal energy storage providing a source of firm capacity at full generator nameplate. The Public Service system load typically peaks two to four hours after solar noon when the solar resource peaks. Thermal storage "firms" the generating unit's capacity by oversizing the thermal output capability of the solar collector field relative to the thermal input capability of the generator, storing the excess thermal energy, and later releasing the energy to generate steam during solar transients (e.g., clouds), as the solar resource decreases after solar noon, or after sunset. The value that thermal

[25] "Solar Photovoltaics: Financing a Strategic Industry in the United States," Deutsche Bank, May 6, 2010. Currently available at: http://solar.gwu.edu/index_files/Resources_files/Financing%20Solar%20PV%20industry%20in%20the%20US_6%20May%202010_DB_ORourke.pdf

[26] "Final Report: Solar Integration Study for Public Service Company of Colorado," Xcel Energy Inc. and EnerNex Corporation, February 9, 2009.

storage adds is a function of the solar multiple (i.e., the ratio of the solar field's thermal output capability at a design solar resource level to the steam generator's input capability), the solar resource at the facility site, and the hourly cost of energy.

For the alternative plans studied, an hourly generation profile for a solar trough plant with six hours of thermal storage located in the San Luis Valley was used. This profile is consistent with that of the facility targeted to meet the 200 MW minimum solar with storage set-aside in the 2007 ERP.

Pricing for the 125 MW and 50 MW solar thermal with storage facilities was based on indicative pricing levels in the 2009 All-Source RFP and DOE cost reduction targets.[27] 10% ITC solar project pricing (for projects with in-service dates in 2017 and 2018) was set to 125% of the 30% ITC pricing based on a revenue requirements model analysis.

Retail DG Description

To date, all of the Company's Retail DG generation resources have been acquired through the Company's Solar*Rewards program designed to acquire Retail DG RECs from photovoltaic sources. The MW levels of installed Retail DG were taken from the 2014 RES Compliance Plan. Hourly annual, Retail DG generation curves are based on historical PV meter data obtained from utility-scale solar generation systems and Solar*Reward-funded Retail DG projects.

Representation of Generic Resource Costs

An Economic Carrying Charge ("ECC") is used to represent capital costs of the generic resources. The economic carrying charge is the preferred method to evaluate the economic value of using a facility for part of its life and thus allows resources of different lives to be compared. See Attachment 2.8-5 provided at the end of this section for an explanation of the ECC. Table 2.8-3(a) shows the annual total capacity costs of each dispatchable generic resource that is considered in the RAP. The total capacity cost is the sum of the capital ECC, fixed O&M and gas demand costs. Table 2.8-3(b) shows the annual $/MWh costs of each generic renewable resource assuming a 2017 COD.

[27] "Line-Focus Solar Power Plant Cost Reduction Plan," NREL/TP-5500-48175, December 2010.

Table 2.8-3(a) Total Capacity Costs of RAP Dispatchable Generic Resources

Year	2x1[1] Combined Cycle ($/kw-mo)	1x1[1] Combined Cycle ($/kw-mo)	Combustion Turbine (1st)[1,2] ($/kw-mo)	Combustion Turbine (2nd)[1,2] ($/kw-mo)	Battery ($/kw-mo)
2011	$9.00	$9.21	$4.70	$3.46	$31.25
2012	$9.16	$9.46	$4.83	$3.56	$32.12
2013	$9.33	$9.70	$4.97	$3.66	$33.02
2014	$9.50	$9.96	$5.11	$3.76	$33.95
2015	$9.68	$10.22	$5.25	$3.87	$34.90
2016	$9.86	$10.49	$5.40	$3.98	$35.88
2017	$10.05	$10.77	$5.55	$4.09	$36.88
2018	$10.24	$11.05	$5.70	$4.20	$37.91
2019	$10.44	$11.35	$5.86	$4.32	$38.98
2020	$10.64	$11.65	$6.03	$4.44	$40.07
2021	$10.85	$11.96	$6.20	$4.57	$41.19
2022	$11.06	$12.27	$6.37	$4.70	$42.34
2023	$11.28	$12.60	$6.55	$4.83	$43.53
2024	$11.51	$12.94	$6.73	$4.96	$44.75
2025	$11.74	$13.28	$6.92	$5.10	$46.00
2026	$11.98	$13.64	$7.11	$5.25	$47.29
2027	$12.23	$14.00	$7.31	$5.39	$48.61
2028	$12.48	$14.38	$7.52	$5.54	$49.97
2029	$12.75	$14.77	$7.73	$5.70	$51.37
2030	$13.01	$15.16	$7.95	$5.86	$52.81
2031	$13.29	$15.57	$8.17	$6.02	$54.29
2032	$13.57	$15.99	$8.40	$6.19	$55.81
2033	$13.86	$16.42	$8.63	$6.37	$61.50
2034	$14.16	$16.87	$8.88	$6.54	$63.23
2035	$14.47	$17.32	$9.12	$6.73	$65.00
2036	$14.79	$17.79	$9.38	$6.92	$66.82
2037	$15.11	$18.27	$9.64	$7.11	$68.69
2038	$15.45	$18.77	$9.91	$7.31	$70.61
2039	$15.79	$19.28	$10.19	$7.51	$72.59
2040	$16.14	$19.80	$10.48	$7.73	$74.62
2041	$16.51	$20.34	$10.77	$7.94	$76.71
2042	$16.88	$20.89	$11.07	$8.16	$78.86
2043	$17.26	$21.46	$11.38	$8.39	$81.06
2044	$17.66	$22.05	$11.70	$8.63	$83.33
2045	$18.06	$22.65	$12.03	$8.87	$85.67
2046	$18.48	$23.27	$12.37	$9.12	$88.07
2047	$18.91	$23.90	$12.71	$9.37	$90.53
2048	$19.35	$24.55	$13.07	$9.64	$93.07
2049	$19.80	$25.23	$13.44	$9.91	$95.67
2050	$20.27	$25.92	$13.81	$10.19	$98.35

(1) Costs for the 2x1 and 1x1 combined cycle and combustion turbine represent an average of greenfield and brownfield estimates. These average costs are used to represent resources available in the RAP.

(2) Combustion turbines (CTs) are generally constructed in pairs to take advantage of economies of scale. A two unit projects is estimated to cost 170% of a one unit project. A single CT or pair of CTs were considered in the RAP. If two CTs are added in one year, the second CT is assumed to cost 70% of the cost of the 1st CT.

Table 2.8-3(b) Total $/MWh Costs of RAP Renewable Generic Resources

YEAR	non-PTC Wind ($/MWh)	PTC Wind ($/MWh)	10% ITC Solar PV ($/MWh)	30% ITC Solar PV ($/MWh)	10% ITC 50 MW Solar Thermal ($/MWh)	10% ITC 125 MW Solar Thermal ($/MWh)	30% ITC 50 MW Solar Thermal ($/MWh)	30% ITC 125 MW Solar Thermal ($/MWh)
2016	$62.30	$32.30						
2017	$62.90	$32.90	$107.80	$82.10				
2018	$63.40	$33.40	$110.50	$84.20	$202.33	$178.20	$162.33	$142.38
2019	$64.00	$34.00	$113.30	$86.30	$206.40	$181.80	$165.60	$145.20
2020	$64.60	$34.60	$116.20	$88.50	$210.50	$185.40	$168.90	$148.10
2021	$65.30	$35.30	$119.20	$90.80	$214.70	$189.10	$172.30	$151.10
2022	$65.90	$35.90	$122.20	$93.10	$219.00	$192.90	$175.70	$154.10
2023	$66.50	$36.50	$125.30	$95.50	$223.40	$196.80	$179.20	$157.20
2024	$67.20	$37.20	$128.50	$97.90	$227.90	$200.70	$182.80	$160.30
2025	$67.80	$37.80	$131.80	$100.40	$232.50	$204.70	$186.50	$163.50
2026	$68.50	$38.50	$135.20	$103.00	$237.20	$208.80	$190.20	$166.80
2027	$69.20	$39.20	$138.60	$105.60	$241.90	$213.00	$194.00	$170.10
2028	$69.90	$39.90	$142.10	$108.30	$246.70	$217.30	$197.90	$173.50
2029	$70.60	$40.60	$145.80	$111.00	$251.60	$221.60	$201.90	$177.00
2030	$71.30	$41.30	$149.50	$113.90	$256.60	$226.00	$205.90	$180.50
2031	$72.10	$42.10	$153.30	$116.80	$261.70	$230.50	$210.00	$184.10
2032	$72.80	$42.80	$157.20	$119.70	$266.90	$235.10	$214.20	$187.80
2033	$73.60	$43.60	$161.20	$122.80	$272.20	$239.80	$218.50	$191.60
2034	$74.30	$44.30	$165.30	$125.90	$277.60	$244.60	$222.90	$195.40
2035	$75.10	$45.10	$169.50	$129.10	$283.20	$249.50	$227.40	$199.30
2036	$75.90	$45.90	$173.90	$132.40	$288.90	$254.50	$231.90	$203.30
2037	$76.70	$46.70			$294.70	$259.60	$236.50	$207.40
2038	$77.60	$47.60			$300.60	$264.80	$241.20	$211.50
2039	$78.50	$48.50			$306.60	$270.10	$246.00	$215.70
2040	$79.30	$49.30			$312.70	$275.50	$250.90	$220.00
2041	$80.20	$50.20			$319.00	$281.00	$255.90	$224.40
2042	$81.10	$51.10			$325.40	$286.60	$261.00	$228.90

2. Modeling the Alternative Plans

The Strategist modeling for construction of the “at least three alternate plans” required by ERP Rule 3604(k) is described in the following two subsections:

a. Development and Results of the Least-Cost Baseline Case
b. Development of the Alternative Plans

a. Development of the Least-Cost Baseline Case

The Commission’s Electric Resource Planning Rules (“ERP Rules”) at ERP Rule 3604(k) require that the Company provide descriptions of at least three plans that can be used to represent the costs and benefits from increasing amounts of renewable energy resources, demand-side resources or Section 123 Resources. One of the plans shall represent a baseline case that describes the costs and benefits of the new utility resources required to meet the utility’s needs during the planning period that minimizes the net present value of revenue requirements and complies with the Renewable Energy Standard as well as the demand-side resource requirements. Public Service refers to this plan as the “least-cost baseline case”. The discussion that follows describes the development of the baseline case.

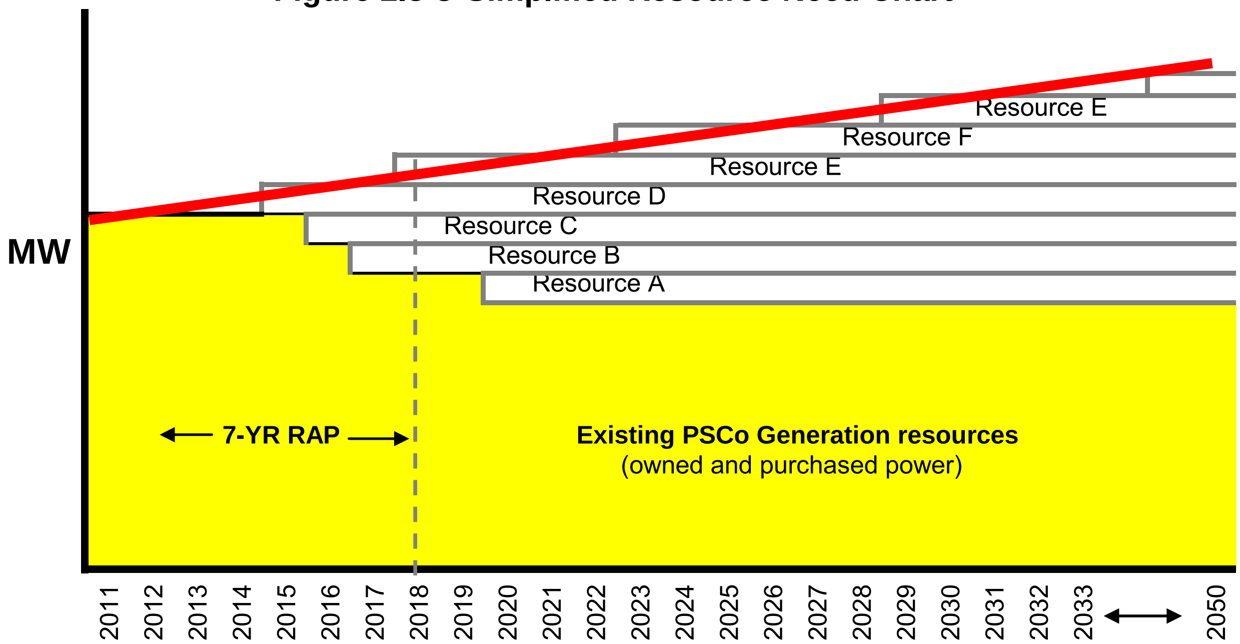
Demand-Side Resource Requirements

The impacts of demand-side resource requirements in reducing firm load obligation are embedded in the load forecast and are described in more detail in Section 2.4.

Renewable Energy Standard Requirements

ERP Rule 3604(k) states that the baseline case and alternative plans must comply with the Renewable Energy Standard, 4 CCR 723-3-3650. To determine if Public Service could use Strategist to economically select sufficient levels of renewable resources needed to meet the RES requirements, the Company performed a Strategist run allowing the model flexibility to add renewable resources if they were part of a least-cost plan. We refer to this model run herein as the “open” Strategist run. Figure 2.8-3 shows a graphical depiction of how Strategist utilizes resource options available to it (in this case all generic resources in Tables 2.8-1 and 2.8-2) to meet future resources needs over time.

Figure 2.8-3 Simplified Resource Need Chart



This open Strategist run did not select sufficient levels of renewable energy resources needed to meet the RES through the planning period. The resulting expansion plan of this run are shown in Table 2.8-4. Note that the open run assumed that all existing renewable resources would retire or expire at the end of their lives or contract terms. Therefore, the open run does not economically add enough renewable resources to replace the existing resource let alone add enough to meet the RES.

Table 2.8-4 Generic Expansion Plan of the Open Run

Year	Baseload[1]	2x1[1] Combined Cycle	1x1[1] Combined Cycle	Combustion Turbine[1]	Battery	Wind[2]	Solar PV[2]	Solar Thermal[2]
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018				346 MW				
2019				173 MW				
2020				173 MW				
2021				173 MW				
2022				346 MW				
2023		643 MW						
2024								
2025								
2026								
2027		643 MW						
2028								
2029				173 MW				
2030						200 MW		
2031				173 MW			100 MW	
2032		643 MW						
2033								
2034		643 MW						
2035								
2036		643 MW						
2037								
2038								
2039								
2040								
2041								
2042	485 MW	643 MW						
2043						200 MW	25 MW	
2044						200 MW	25 MW	
2045						100 MW		
2046						200 MW	25 MW	
2047						100 MW		
2048						100 MW		
2049				346 MW				
2050								

(1) Listed as summer accredited capacity rating
(2) Listed as nameplate capacity

In order to ensure that the baseline case met the RES through the planning period as required by Commission rule 3604(k), renewable energy resources were manually added into the model (a.k.a., locked down) over time. To develop the amount and timing of renewable energy resources, the following assumptions were applied:

1) All Renewable Energy Credits ("REC") would be used for compliance with the RES. No RECs are assumed to be sold and no RECs would be allowed to expire unused. For instance, the retail DG standard is assumed to be met for all years in the Planning

Period. Instead of allowing RECs to expire, all excess retail DG RECs are carried over to the wholesale DG or non-DG categories so that they are used for compliance.

2) The retail DG solar forecast is set as shown in Table 2.8-5. Generic wind resources in 100 MW increments and generic solar PV resources in 25 MW increments were the two renewable energy resources used overtime to comply with the wholesale DG and non-DG requirements of the RES.
3) The current or currently contracted level of wind and utility scale solar PV will be renewed at the end of the current contract terms. The retiring or expiring resources are replaced with similarly sized wind, e.g., a 200 MW wind resource would be replaced with two 100 MW generic wind resources, and solar PV resources. For simplicity, smaller renewable energy resources such as biomass or hydro were not replaced at the end of their current contracts.
4) Additional generic wind and generic solar PV resources were added so that the bank of excess RECs would have a “soft” landing by 2050. In other words, the RECs are used in such a manner that by 2050, any bank is used up and annual REC generation equals approximately what is required by the RES.

Table 2.8-5 shows the wind and solar PV additions added to Strategist in order to comply with ERP Rule 3604(k). These levels of future renewable resources were included in all alternative plans including the least-cost baseline case. Alternative plans A2 through A5 and B2 through B5 include these Table 2.8-5 level of renewables plus additional renewables in the RAP as identified in Figure 1.5-3 of ERP Volume 1.

Table 2.8-5 Additional Future Renewable Energy in All Alternative Plans

Year[1]	Retail DG	Replacement Wind[2]	Incremental Wind[3]	Replacement PV[4]	Incremental PV[5]
2011	38 MW				
2012	36 MW				
2013	34 MW				
2014	34 MW				
2015	31 MW				
2016	31 MW				
2017	31 MW				
2018	31 MW				
2019	31 MW	100 MW			
2020	31 MW				
2021	31 MW				
2022	31 MW				
2023	31 MW				
2024	31 MW				
2025	31 MW		200 MW		
2026	31 MW				
2027	31 MW				
2028	31 MW	600 MW			
2029	31 MW				
2030	31 MW				
2031	31 MW			100 MW	
2032	31 MW	300 MW			
2033	31 MW	200 MW			
2034	31 MW				
2035	31 MW	200 MW			
2036	31 MW				
2037	31 MW	200 MW			
2038	31 MW	400 MW			
2039	31 MW				
2040	31 MW		100 MW		
2041	31 MW				
2042	31 MW				
2043	31 MW	100 MW			
2044	31 MW				
2045	31 MW				
2046	31 MW				
2047	31 MW				
2048	31 MW				
2049	31 MW				
2050	31 MW				

Notes:
[1] All values are nameplate additions. Retail DG solar shown as AC nameplate
[2] Replacement wind replaces expiring wind contracts with similar sized generic wind
[3] Incremental wind is generic wind added above existing portfolio to meet RES compliance
[4] Replacement solar replaces expiring solar contracts with similar sized generic solar PV
[5] Incremental solar is generic solar added above existing portfolio to meet RES compliance

Future Baseload Resources in Generic Expansion Plan

A well planned electrical energy resource portfolio will generally include a balanced mix of low energy cost resources (e.g. coal or nuclear) that meet minimum energy needs, peaking resources that provide energy to the system during a relatively few hours of the year (e.g. combustion turbines) and intermediate resources that are flexible and can have their electrical output be ramped up and down with demand while also providing relatively inexpensive energy compared to peaking resources.

In the Strategist modeling of the Public Service system all Company-owned thermal resources were modeled to retire at their book retirement dates and all contracts with thermal resources such as gas-fired CTs, expire at the end of their contract terms. All of Public Service's owned baseload thermal resources and baseload contracts retire and/or expire during the Planning Period except for Comanche 3. As a result, towards the end of the 2011-2050 Planning Period, the Strategist model contains only the 500 MW Comanche 3 baseload unit.

To maintain a more balanced mix of generation supply in the Strategist model, Public Service added a 500 MW generic baseload resource in 2042 after the retirement of Pawnee. With this addition, 1000 MW of baseload generation was included in Strategist from 2042-2050.

Application of Seasonal Capacity Purchases

The WECC is forecasting an oversupply of generation capacity within the WECC area through 2018. In developing the alternative plans Public Service assumed that some of this excess generation capacity would be available for purchase to meet generation needs for years 2011-2017. Therefore, Strategist was allowed to purchase up to 85 MW (1/2 of a combustion turbine) to meet need for years 2011-2017 at a price of $2.79/kw-mo escalating at inflation for the four summer months of each year. In years beyond 2017, Strategist is not allowed to purchase seasonal capacity but must meet need through addition of generic generation resources.

Resulting Generic Expansion Plan

After manually locking down the renewable resources to meet the RES through 2050, the addition of 500 MW of baseload resources and adding an allowance for seasonal capacity purchases, Strategist was allowed to meet the remaining need in a least-cost manner through optimizing the addition of combustion turbines and 2x1 and 1x1 combined cycle resources. Figure 2.8-4 shows an exaggerated version of Figure 2.8-3 to illustrate how additional resources are added by the Strategist model to build the least-cost baseline case. Table 2.8-6 shows the resources added to build the baseline case expansion plan.

Figure 2.8-4 Generic Resources Added to Meet Demand

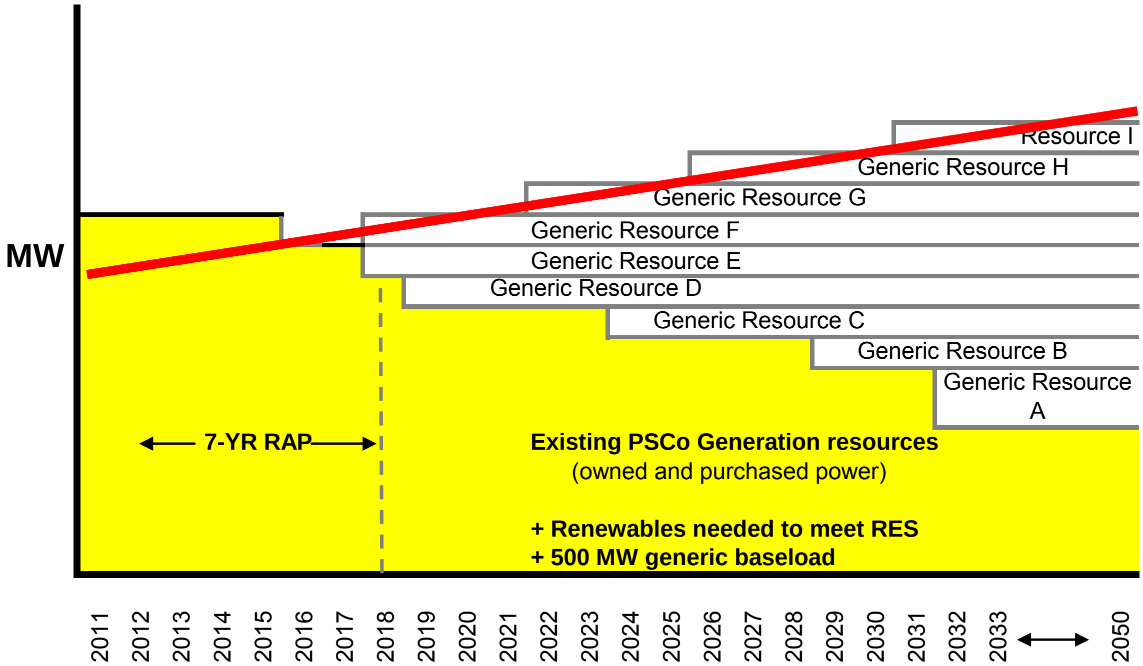


Table 2.8-6 Generic Expansion Plan of the Least-Cost Baseline Case

Year	Baseload[1]	2x1[1] Combined Cycle	1x1[1] Combined Cycle	Combustion Turbine[1]	Battery	Wind[2]	Solar PV[2]	Solar Thermal
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018				346 MW				
2019				173 MW		100 MW		
2020				173 MW				
2021				173 MW				
2022				346 MW				
2023		643 MW						
2024								
2025						200 MW		
2026								
2027		643 MW						
2028						600 MW		
2029								
2030				173 MW				
2031				173 MW			100 MW	
2032						300 MW		
2033		643 MW				200 MW		
2034				173 MW				
2035						200 MW		
2036		643 MW						
2037						200 MW		
2038						400 MW		
2039								
2040				173 MW		100 MW		
2041								
2042	485 MW	643 MW		173 MW				
2043						100 MW		
2044								
2045								
2046								
2047								
2048		643 MW						
2049								
2050								

(1) Listed as summer accredited capacity rating

(2) Listed as nameplate capacity. Renewable energy additions shown include additions to replace expiring contracts.

During the 2012-2018 RAP, Strategist filled the need in 2017 with a seasonal purchase of 59 MW and filled the 2018 need with two combustion turbines (346 MW summer capacity). Table 2.8-7 shows an abbreviated Load and Resource table for the least-cost baseline case and how the RAP need is met by the addition of two generic combustion turbines.

Table 2.8-7 Baseline Case Loads and Resources Table

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
1-Baseline Case							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind							
Utility Scale PV							
Total Renewables	0	0	0	0	0	0	0
Section 123 Resources							
Small storage (batteries)							
Solar Thermal with Storage							
Total Section 123 Resources	0	0	0	0	0	0	0
Other Resources							
Seasonal Purchase						59	
Generic Combustion Turbine							346
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	59	346
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**0**	**(54)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.
[2] All values are shown as the summer accredited capacity

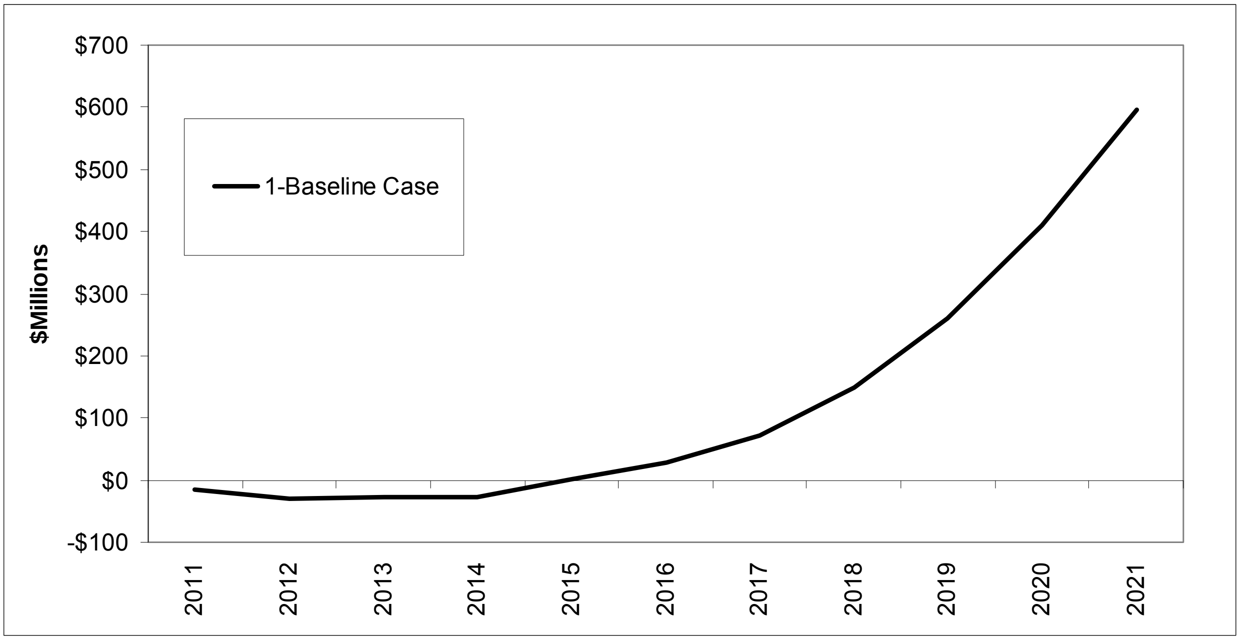
Note that after the addition of the two CTs in 2018, the baseline case portfolio has an excess of 54 MW of capacity.[28] In years beyond 2018, to the degree that this 54 MW excess capacity in 2018 persists, the baseline case is credited at a $/kW-mo rate of a generic CT up to 500 MW of surplus capacity.

Attachment 2.8-2 at the end of this section contains annual emissions of SO_2, NOx, CO_2, Mercury and PM emissions as required by ERP Rule 3604(g).

Figure 2.8-5 includes an estimated RESA balance of the least-cost baseline case. Note that since no additional renewable resources are included in the least-cost baseline case prior to year 2021, the RESA impacts in Figure 2.8-5 are the result of existing or planned renewable resources on the Public Service system as a result of the 2007 ERP and Solar*Rewards.

[28] The official loads and resources table and the Strategist model have a 3 MW discrepancy. This difference is immaterial to the evaluation. The loads and resources tables shown in this Section 2.8 show the values that match with the official loads and resources table in Attachment 2.11-1.

Figure 2.8-5 RESA Balance: Least-Cost Baseline Case



b. Development of the Alternative Plans

Public Service developed eight alternative plans in addition to the least-cost baseline case. These plans add increasing levels of renewable resources and Section 123 resources above that included in the baseline case. The additional renewable resources included in these eight alternative plans are identified in Table 2.8-8. The solar thermal addition in plans A5 and B5 has storage and thus is assumed to be a Section 123 Resource. The battery is also assumed to be a Section 123 Resource. Level A and B give two "bookend" levels of increasing levels of resource additions allowing a reader to estimate the costs and benefits of levels of renewable and Section 123 Resources between the bookends based upon the results of the alternative plan analysis.

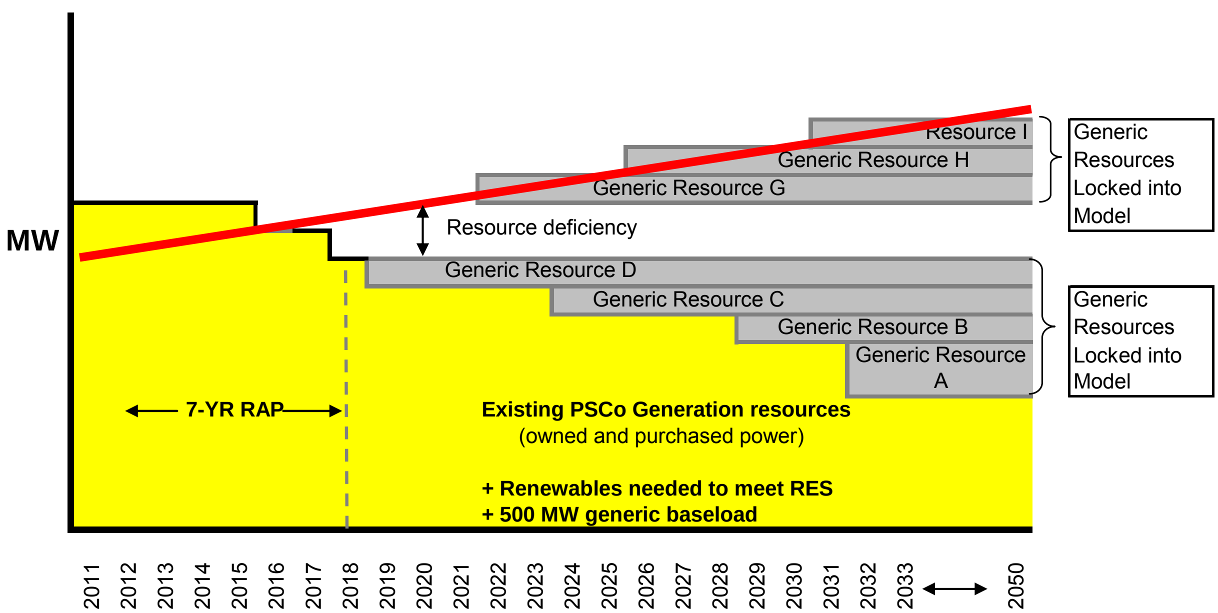
Table 2.8-8 Alternative Plan Resources Added

		Level A				Level B			
RAP Resource	1 Baseline	A2 Wind	A3 PV	A4 Battery	A5 Solar Thermal	B2 Wind	B3 PV	B4 Battery	B5 Solar Thermal
Wind		200 MW	200 MW	200 MW	200 MW	800 MW	800 MW	800 MW	800 MW
Solar PV			25 MW	25 MW	25 MW		100 MW	100 MW	100 MW
Battery				25 MW				100 MW	
Solar Thermal					50 MW				125 MW

Modeling of the Costs and Benefits of the Alternative Plans
Public Service employed a similar modeling convention as that used by the Company and approved by the Commission in Docket No. 07A-447E. This involved taking the generic resources included in the least-cost baseline case for years 2019-2050 and manually locking those resources down within the Strategist model. Evaluating the alternative plans within a common generic plan future in this manner helps ensure that differences in the PVRR between scenarios are almost entirely the result of differences between the different generation technologies included in the RAP of each alternative plans versus differences in the mix of speculative generic resources in the later years of the analysis. Note that the term "locked down" refers to the fact that a generic resource is hardwired into the Strategist model to begin its operating life in a specific year as opposed to being modeled in a fashion where it has a floating in-service date that is ultimately selected by the model based on economics. All generic resources "locked down" in the model were still capable of being economically dispatched with the rest of the fleet to meet customer load in a least-cost manner with the exception of wind and solar PV which are not capable of being dispatched.

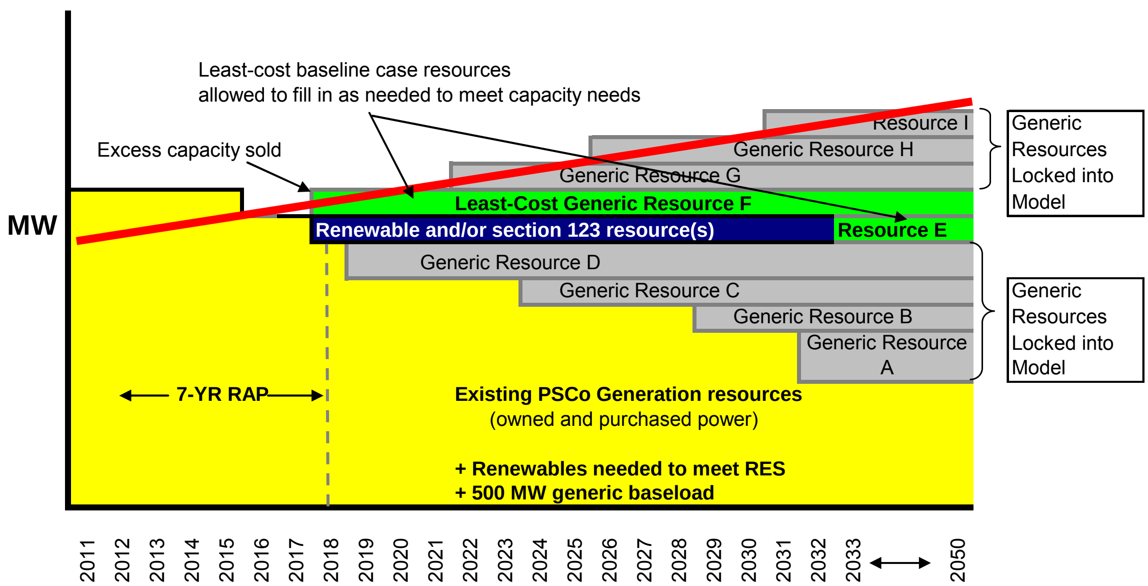
Figure 2.8-6 shows a graphical depiction of the generics that are locked down.

Figure 2.8-6 Depiction of Strategist w/Locked Down Resources



Once the generics in the tail are "locked down", the renewable energy resources and Section 123 resources in each alternative plan are manually added to the model during the RAP to meet a portion of the need. Strategist was allowed the flexibility to add up to two generic combustion turbines in the RAP to meet any remaining capacity need. Since these renewable energy and Section 123 Resources added during the RAP may not provide enough summer accredited capacity to replace the baseline case RAP CTs and will retire/expire before the end of the Planning Period, the least-cost baseline case RAP resources (the 2 CTs) are also allowed to fill in any capacity needs as needed through the Planning Period. In this regard, the annual costs of each alternative plan revert back to that of the least-cost baseline case once the added renewable and Section 123 resources reach the end of their useful lives. Figure 2.8-7 shows how the least-cost resources fill in as needed to meet capacity requirements.

Figure 2.8-7 Illustration of Alternative Plan Resource Additions



If addition of a renewable or Section 123 Resource did not provide enough capacity to replace one or both RAP CTs, the summer accredited capacity from that resource added to the surplus capacity and was credited with the surplus capacity credit up to 500 MW of surplus capacity.

As an example, in Alternative Plan A2, 200 MW of wind was added in 2016. Wind has a 12.5% effective load carrying capability so 200 MW provides 25 MW of summer accredited capacity to meet resource requirements. The capacity need in 2018 is 292 MWs and a CT provides 173 MW of summer accredited capacity.

292 MW need - 25 MW wind = 267 MW (still need two 170 MW CTs)

The 25 MW of firm generation from 200 MW of nameplate wind was not enough capacity to delay the addition of either of the RAP CTs so the 25 MW adds to the surplus capacity of the plan. This additional 25 MW receives a cost credit at the $/kW-yr price of surplus capacity as long as the plan did not have surplus capacity in excess of 500 MW each year. Table 2.8-9 shows how the capacity credit was applied to the 200 MW of wind added in Alternative Plan A2. Note that in Alternative Plan A2, the wind did not receive a surplus capacity credit for two out of the 25 year life because the plan had more than 500 MW of surplus capacity in those years. This is a realistic representation of a system since resource additions tend to be “lumpy”.

Table 2.8-9 Wind Capacity Credit for Alternative Plan A2

A	B	C	D=B*C	E	F=D*E	G	H=G+D	F if H<500
Year	**Wind Added (MW)**	**Wind ELCC Capacity Credit (%)**	**Wind Capacity Credit (MW)**	**Capacity Credit Value ($/kw-yr)**	**Capacity Credit Value ($000)**	**Baseline Surplus Capacity (MW)**	**A2 Surplus Capacity (MW)**	**A2 Surplus Capacity Credit ($000)**
2016	200	12.5%	25	$12.19	$305	-168	-193	$305
2017	200	12.5%	25	$12.41	$310	61	36	$310
2018	200	12.5%	25	$12.63	$316	-52	-77	$316
2019	200	12.5%	25	$80.82	$2,021	-47	-72	$2,021
2020	200	12.5%	25	$83.08	$2,077	-101	-126	$2,077
2021	200	12.5%	25	$85.41	$2,135	-91	-116	$2,135
2022	200	12.5%	25	$87.80	$2,195	-90	-115	$2,195
2023	200	12.5%	25	$98.40	$2,460	-508	-533	$0
2024	200	12.5%	25	$100.47	$2,512	-336	-361	$2,512
2025	200	12.5%	25	$102.58	$2,564	-305	-330	$2,564
2026	200	12.5%	25	$104.73	$2,618	-229	-254	$2,618
2027	200	12.5%	25	$106.93	$2,673	-506	-531	$0
2028	200	12.5%	25	$109.17	$2,729	-432	-457	$2,729
2029	200	12.5%	25	$111.47	$2,787	-6	-31	$2,787
2030	200	12.5%	25	$113.81	$2,845	-100	-125	$2,845
2031	200	12.5%	25	$116.20	$2,905	-107	-132	$2,905
2032	200	12.5%	25	$118.64	$2,966	-10	-35	$2,966
2033	200	12.5%	25	$121.13	$3,028	-369	-394	$3,028
2034	200	12.5%	25	$123.67	$3,092	-149	-174	$3,092
2035	200	12.5%	25	$126.27	$3,157	-84	-109	$3,157
2036	200	12.5%	25	$128.92	$3,223	-298	-323	$3,223
2037	200	12.5%	25	$131.63	$3,291	-165	-190	$3,291
2038	200	12.5%	25	$134.39	$3,360	-109	-134	$3,360
2039	200	12.5%	25	$137.22	$3,430	-56	-81	$3,430
2040	200	12.5%	25	$140.10	$3,502	-150	-175	$3,502
Capacity Credit PVRR					$22,787			$20,310

3. Modeling Results

The Strategist modeling results for the Alternative Plans are described in the following two subsections:

a) Results for the Alternative Plans
b) Sensitivity Analyses for the Alternative Plans

a. Results of the Alternative Plans

The modeling results for each alternative plan are provided below.

Alternative Plan A2

Alternative plan A2 adds 200 MW of non-PTC wind in 2016. Table 2.8-10 shows an abbreviated Load and Resources table for this plan. Wind was given a firm capacity value of 12.5% of nameplate (25 MW for a 200 MW wind generator). Twenty-five MWs are not enough to fill the capacity need in the RAP so Strategist had to include generic combustion turbines to meet the capacity need.

Table 2.8-10 Alternative Plan A2 Loads and Resources

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
				A2			
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind					25	25	25
Utility Scale PV							
Total Renewables	0	0	0	0	25	25	25
Section 123 Resources							
Small storage (batteries)							
Solar Thermal with Storage							
Total Section 123 Resources	0	0	0	0	0	0	0
Other Resources							
Seasonal Purchase						34	
Generic Combustion Turbine							346
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	34	346
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(190)**	**0**	**(79)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.

[2] All values are shown as the summer accredited capacity

Wind is primarily an energy resource and brings value to the system by displacing energy generation from fossil-fired units. Figure 2.8-8 shows the cost impact of Alternative Plan A2 versus the least-cost baseline case. Positive values indicate added costs of Plan A2 while negative values indicate cost savings of Plan A2. Figure 2.8-18 shows that the addition of 200 MW of Non-PTC wind avoids roughly $20 million in energy costs (i.e., fossil generation) in 2016. These energy savings grow to approximately $60 million by 2040. These savings however are more than offset by the cost of the wind energy which starts at approximately $50 million in 2016 growing to approximately $60 million by 2040. The annual net cost is shown by the solid black line. The net cost of Plan A2 is $98 million PVRR higher than the least-cost baseline case. Figure 2.8-9 shows the estimated RESA impact of Plan A2. Because the 200 MW of wind adds costs, the RESA balance would remain negative for an extra year versus the baseline case.

Figure 2.8-8 System Cost Delta: A2 vs. the Least-Cost Baseline Case

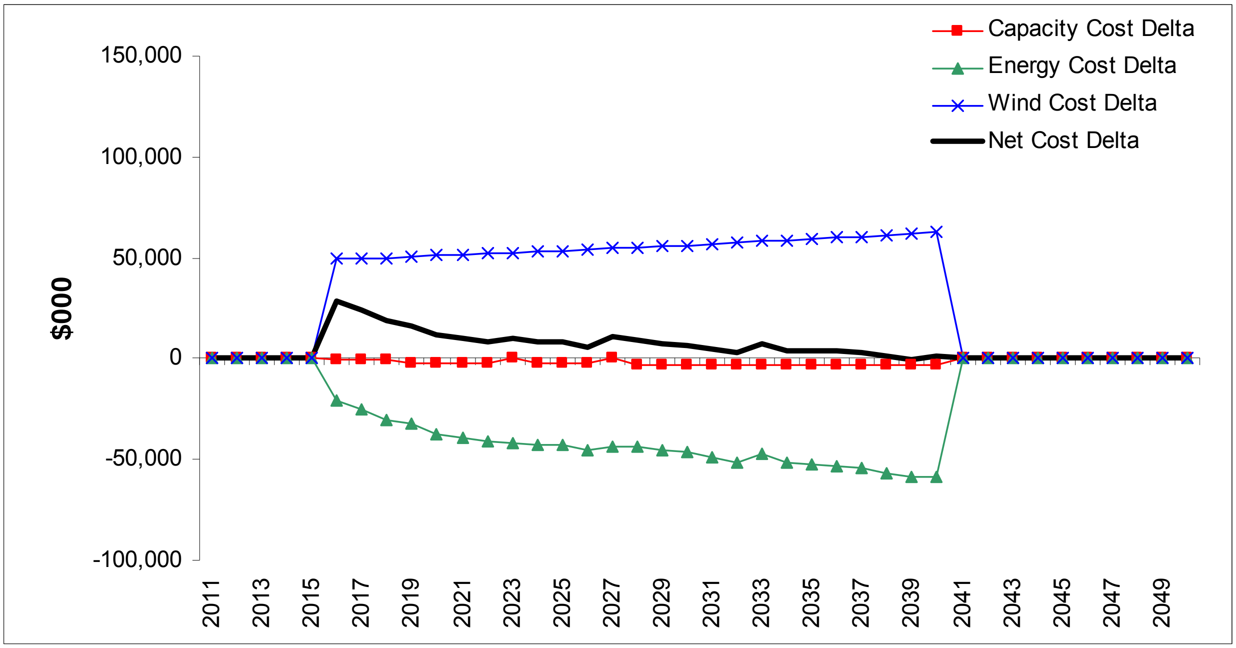
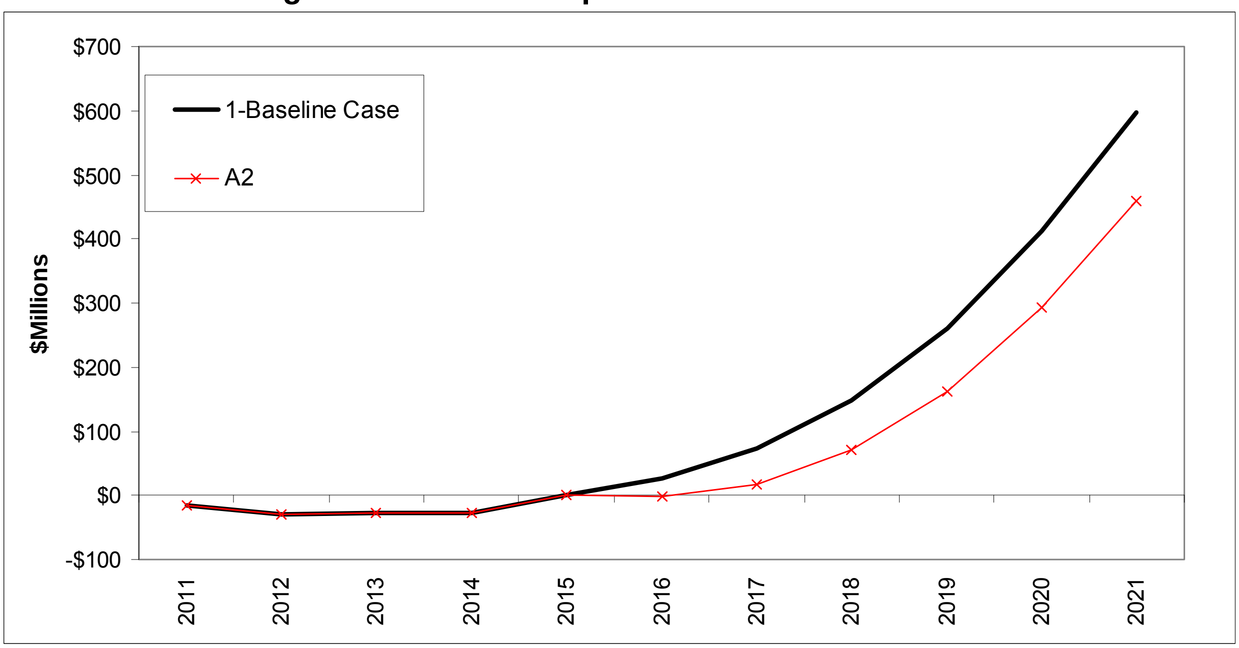


Figure 2.8-9 RESA Impact of Alternative Plan A2



Alternative Plan A3

Alternative Plan A3 adds 25 MW of solar PV with a commercial operations date ("COD") of 12/31/2016 to the 200 MW of wind added in Alternative Plan A2. The solar is added by the end of 2016 in order for it to qualify for the 30% Investment Tax Credit which expires on 12/31/2016.

Table 2.8-11 shows the impact of the addition on meeting the RAP resource need. Solar PV is shown with a firm capacity value equal to 55% of its nameplate rating based on the Company's assumption that PV in the alternative plans consists of highly-efficient PV modules with 1-axis tracking located in the San Luis Valley.

Table 2.8-11 Alternative Plan A3 Loads and Resources

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
A3							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind					25	25	25
Utility Scale PV						14	14
Total Renewables	0	0	0	0	25	39	39
Section 123 Resources							
Small storage (batteries)							
Solar Thermal with Storage							
Total Section 123 Resources	0	0	0	0	0	0	0
Other Resources							
Seasonal Purchase						21	
Generic Combustion Turbine							346
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	21	346
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(190)**	**(0)**	**(93)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.

[2] All values are shown as the summer accredited capacity

Figure 2.8-10 shows the cost impact of Alternative Plan A3 versus the least-cost baseline case. While the added wind and solar PV shows considerable savings in energy costs and some value for capacity, these savings are less than the cost of the wind and solar PV energy. The net impact is that Alternative Plan A3 is $105 million PVRR higher cost than the least-cost baseline case. Figure 2.8-11 shows the annual system cost impact of the solar PV alone by comparing it against Alternative Plan A2. This shows that 25 MW solar PV adds a small amount of cost to the portfolio (the PVRR of Alternative Plan A3 is $7 million higher than the PVRR of Alternative Plan A2).

Figure 2.8-12 shows the RESA impact of this added wind and solar PV. The impact of the solar PV has a minor impact on the RESA balance.

Figure 2.8-10 System Cost Delta: A3 vs. Least-Cost Baseline Case

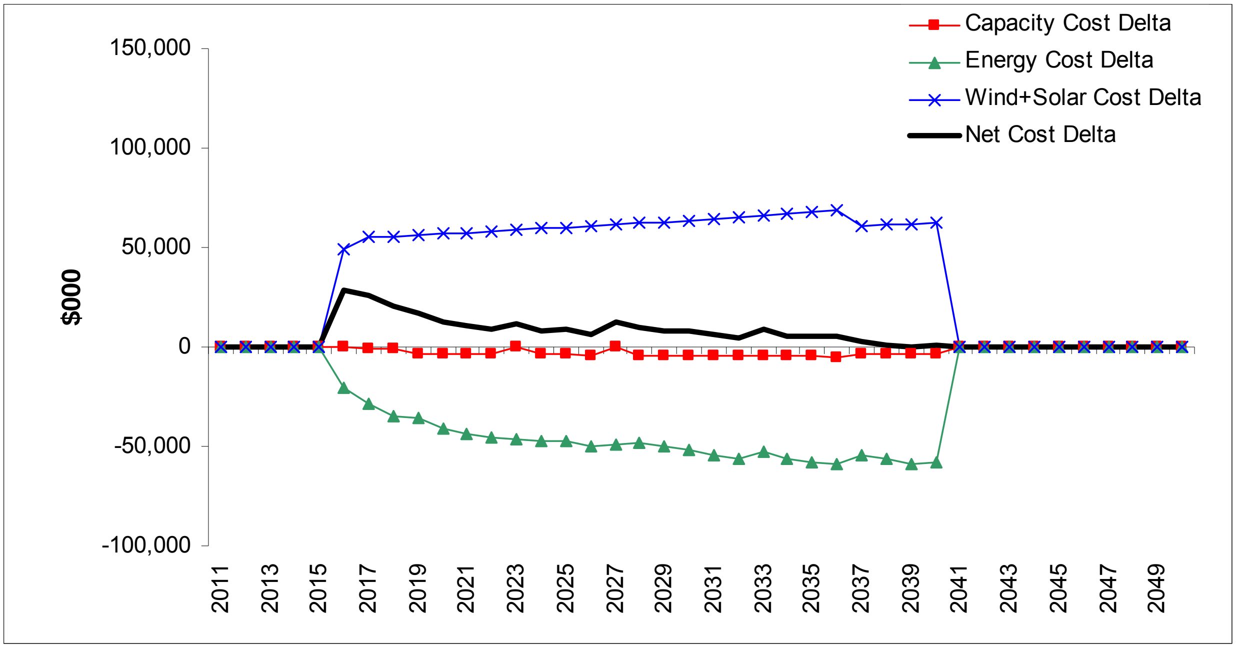


Figure 2.8-11 System Cost Delta: A3 vs. A2

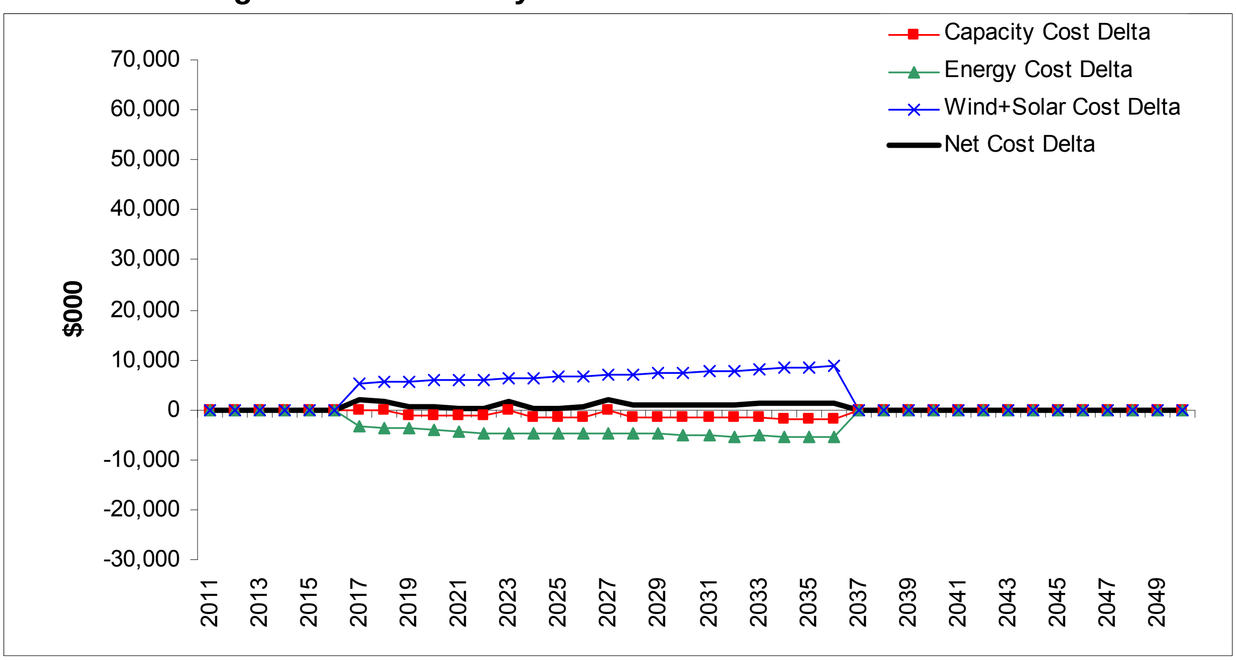
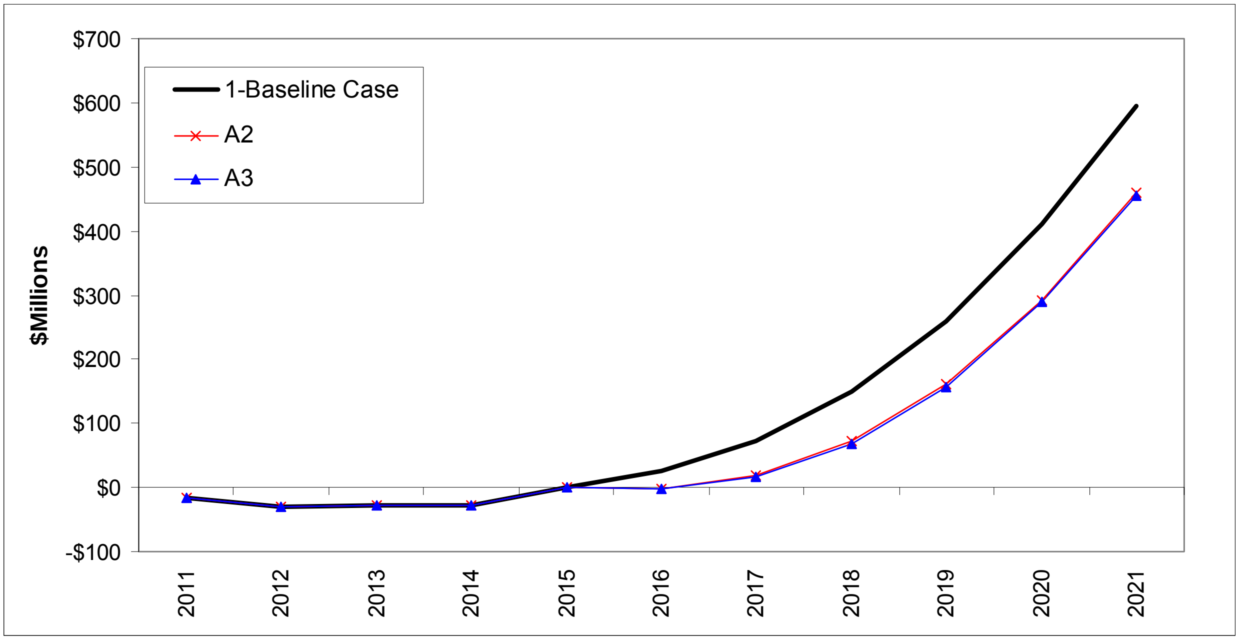


Figure 2.8-12 RESA Impact of Alternative Plan A3



Alternative Plan A4

Alternative plan A4 adds a 25 MW Section 123 battery in 2018 to the 200 MW of non-PTC wind and 25 MW of solar PV added in Alternative Plan A3. Table 2.8-12 shows the impact of the addition on meeting the RAP resource need.

Table 2.8-12 Alternative Plan A4 Loads and Resources

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
A4							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind					25	25	25
Utility Scale PV						14	14
Total Renewables	0	0	0	0	25	39	39
Section 123 Resources							
Small storage (batteries)							25
Solar Thermal with Storage							
Total Section 123 Resources	0	0	0	0	0	0	25
Other Resources							
Seasonal Purchase						21	
Generic Combustion Turbine							346
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	21	346
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(190)**	**(0)**	**(118)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.

[2] All values are shown as the summer accredited capacity

Figure 2.8-13 shows the cost impact of Alternative Plan A4 versus the least-cost baseline case. While the battery shows energy savings the high capital cost of the battery more than offsets these savings. The net impact is that Alternative Plan A4 is $160 million PVRR higher cost compared to the baseline case and is $55 million PVRR higher cost compared to Alternative Plan A3. Figure 2.8-14 shows the annual system cost impact of the battery alone by comparing it against Alternative Plan A3.

The battery is considered a Section 123 Resource. Therefore, it has no impact on the RESA balance.

Figure 2.8-13 System Cost Delta: A4 vs. Least-Cost Baseline Case

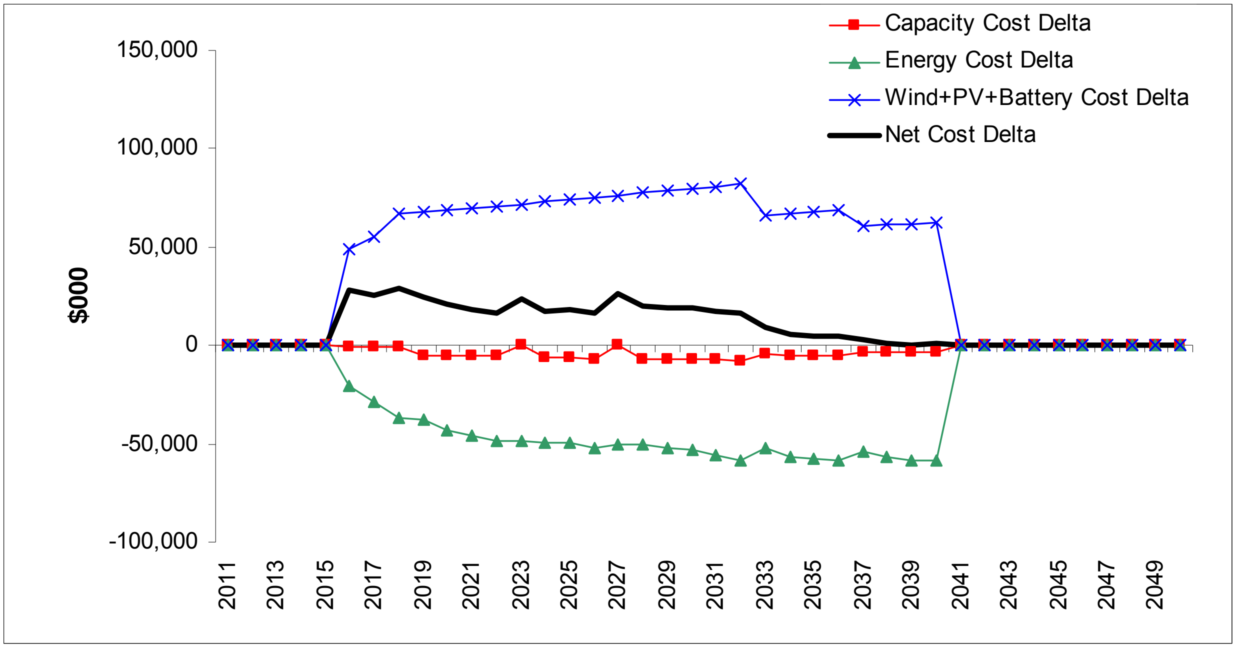
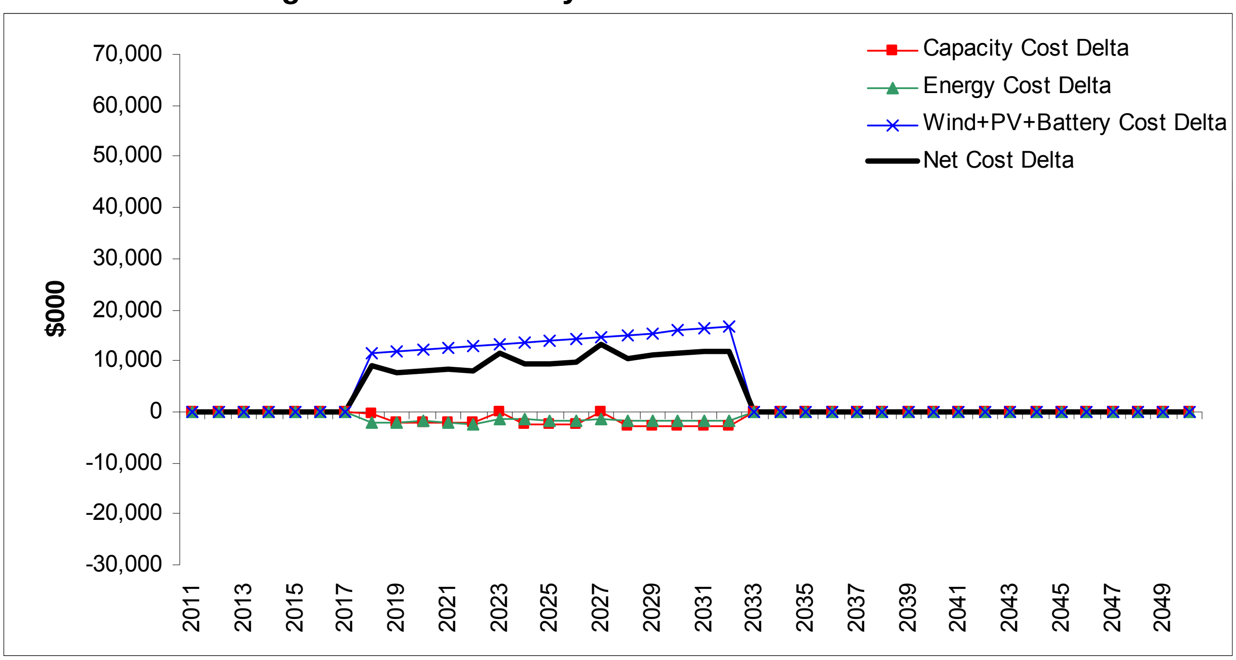


Figure 2.8-14 System Cost Delta: A4 vs. A3



Alternative Plan A5

Alternative plan A5 adds a 50 MW Section 123 solar thermal with storage with 10% ITC in 2018 on top of the 200 MW of non-PTC wind plus 25 MW of solar PV added in Alternative Plan A3.

Table 2.8-13 shows the impact of the addition on meeting the RAP resource need. The excess capacity is credited with the capacity cost of a CT as explained earlier.

Table 2.8-13 Alternative Plan A5 Loads and Resources

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
A5							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind					25	25	25
Utility Scale PV						14	14
Total Renewables	0	0	0	0	25	39	39
Section 123 Resources							
Small storage (batteries)							
Solar Thermal with Storage							50
Total Section 123 Resources	0	0	0	0	0	0	50
Other Resources							
Seasonal Purchase						21	
Generic Combustion Turbine							346
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	21	346
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(190)**	**(0)**	**(143)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.
[2] All values are shown as the summer accredited capacity

Figure 2.8-15 shows the cost impact of Alternative Plan A5 versus the baseline case. Similarly, Figure 2.8-16 shows the annual system cost impact of the solar thermal with storage alone by comparing it against Alternative Plan A3. The net impact is that Alternative Plan A5 is $298 million PVRR higher cost than the baseline case and is $193 million PVRR higher cost when compared with Alternative Plan A3. The solar thermal with storage resource added is a Section 123 Resource. Therefore, it has no impact on the RESA balance.

Figure 2.8-15 System Cost Delta: A5 vs. Least-Cost Baseline Case

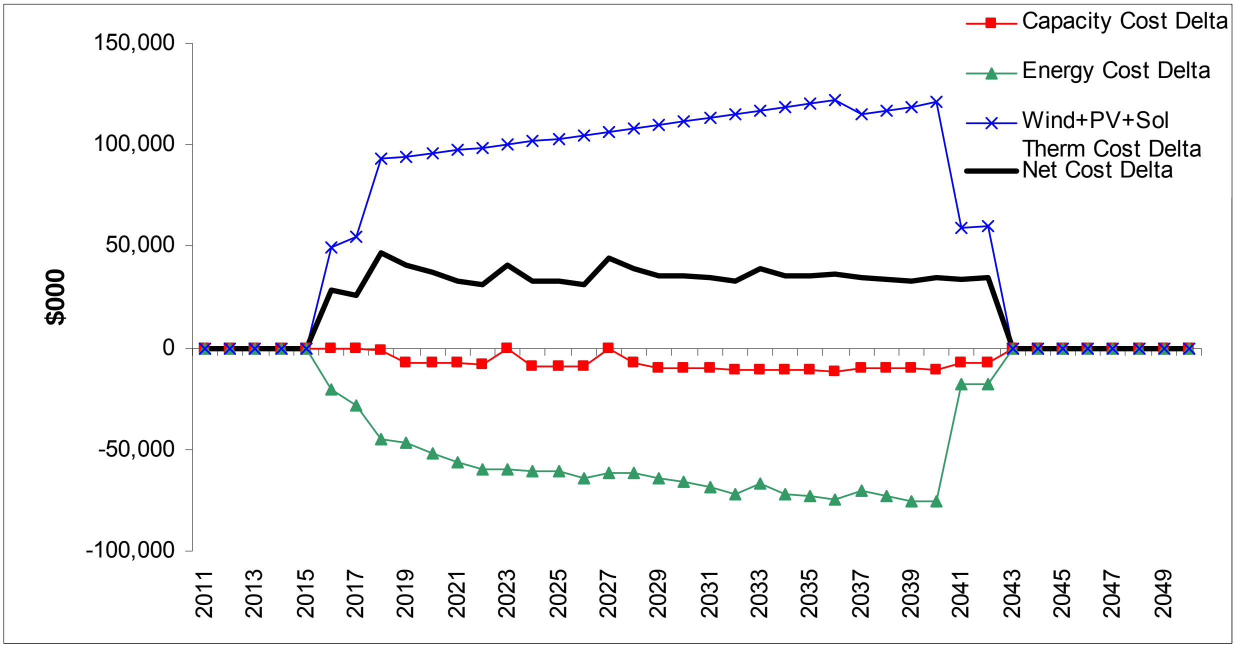
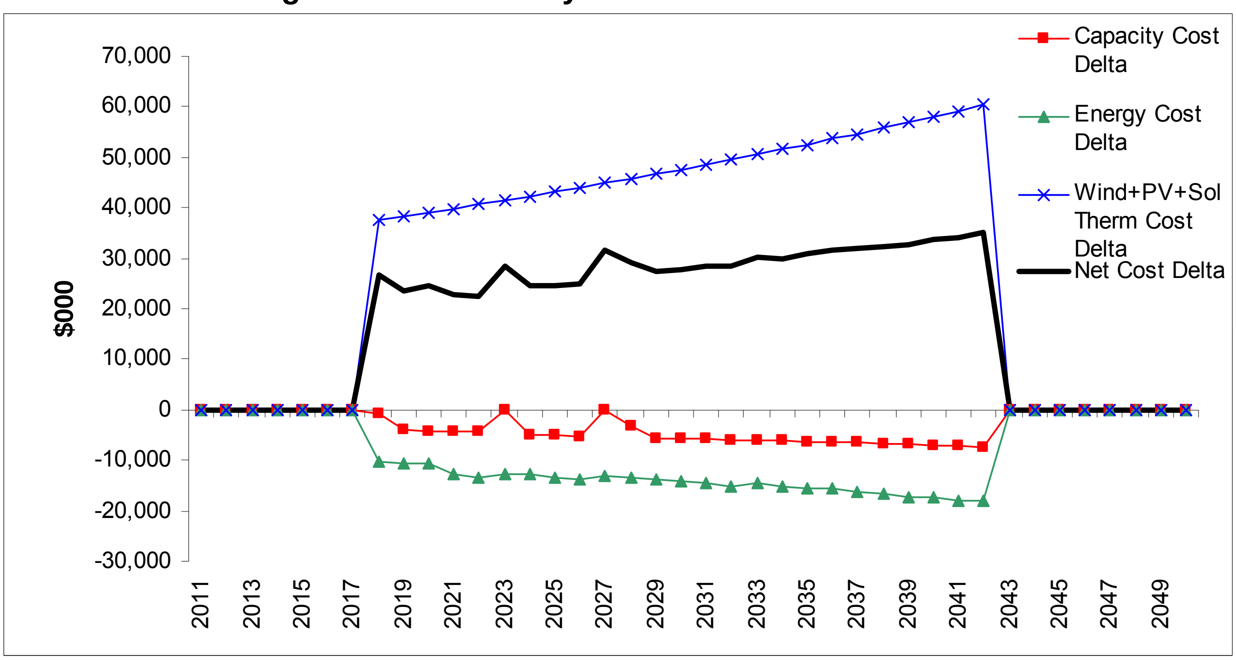


Figure 2.8-16 System Cost Delta: A5 vs. A3



Alternative Plan B2

Alternative plan B2 adds 800 MW of non-PTC wind in 2016-2018. Table 2.8-14 shows the impact of the addition onto the resource need. Wind has a 12.5% effective load carrying capability thereby providing 100 MW of capacity to meet resource needs.

Table 2.8-14 Alternative Plan B2 Loads and Resources

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
B2							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind					25	63	100
Utility Scale PV							
Total Renewables	0	0	0	0	25	63	100
Section 123 Resources							
Small storage (batteries)							
Solar Thermal with Storage							
Total Section 123 Resources	0	0	0	0	0	0	0
Other Resources							
Seasonal Purchase							
Generic Combustion Turbine							346
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	0	346
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(190)**	**(3)**	**(154)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.

[2] All values are shown as the summer accredited capacity

Figure 2.8-17 shows the cost impact of Alternative Plan B2 versus the baseline case. While wind shows considerable savings in energy costs and some value for capacity, these savings are more than offset by the cost of the wind. The net impact is that Alternative Plan B2 is $427 million PVRR higher cost than the least-cost baseline case. Figure 2.8-18 shows the estimated RESA impact of this added wind.

Figure 2.8-17 System Cost Delta: B2 vs. Least-Cost Baseline Case

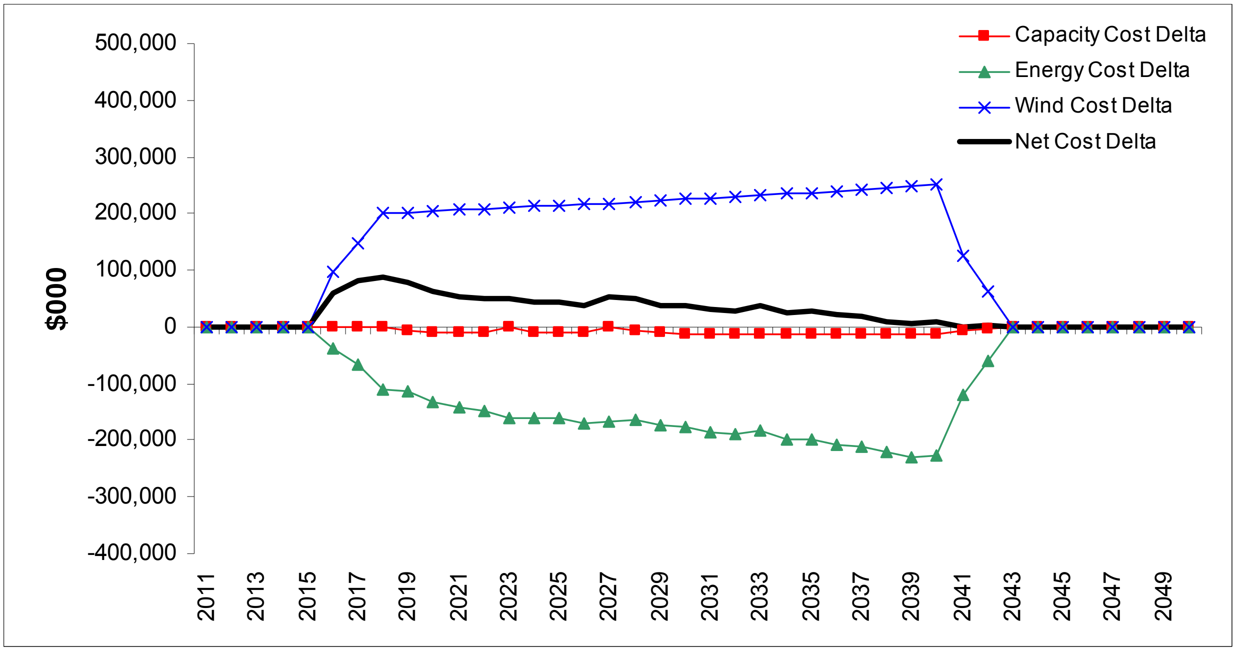
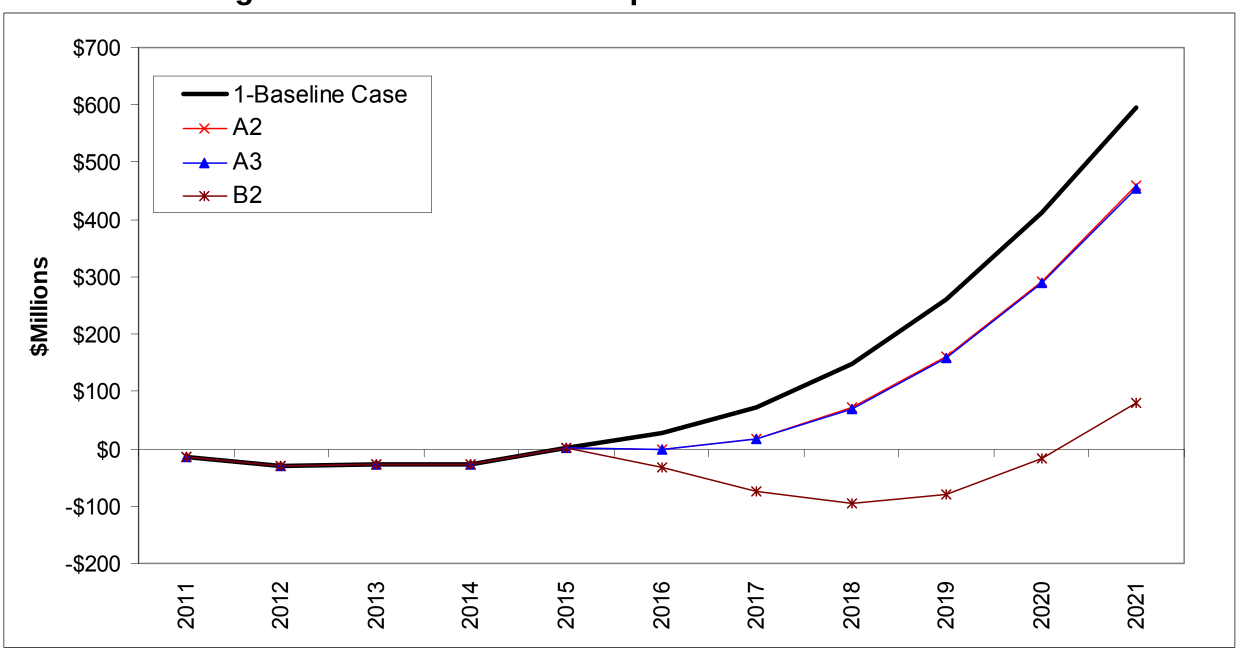


Figure 2.8-18 RESA Impact of Alternative Plan B2



Alternative Plan B3

Alternative Plan B3 adds 100 MW of solar PV with a COD of 12/31/2016 with the 800 MW of wind added in Alternative Plan B2. The solar is added by the end of 2016 in order for it to qualify for the 30% ITC. Table 2.8-15 shows the impact of this addition on the resource need. Note that this plan only needed to add one combustion turbine in 2018 as opposed to two combustion turbines in the least-cost baseline case.

Table 2.8-15 Alternative Plan B3 Loads and Resources

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
B3							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind					25	63	100
Utility Scale PV						55	55
Total Renewables	0	0	0	0	25	118	155
Section 123 Resources							
Small storage (batteries)							
Solar Thermal with Storage							
Total Section 123 Resources	0	0	0	0	0	0	0
Other Resources							
Seasonal Purchase							
Generic Combustion Turbine							173
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	0	173
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(190)**	**(58)**	**(36)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.

[2] All values are shown as the summer accredited capacity

Figure 2.8-19 shows the cost impact of Alternative Plan B3 versus the baseline case. While the added wind and solar PV shows savings in energy costs and some value for capacity, these savings are not more than the cost of adding the wind and solar PV. The net impact is that Alternative Plan B3 is $489 million PVRR higher cost than the baseline case. Figure 2.8-20 shows the annual system cost impact of the solar PV alone by comparing it against Alternative Plan B2. The PVRR of Alternative Plan B3 is $62 million higher than the PVRR of Alternative Plan B2). Note that in this plan there is enough capacity to remove one of the CTs from the RAP. When the plan adds back the CT later in the planning period, it is a CT that is assumed to be available at the time (i.e. a pure greenfield CT with an improved heat rate). This results in a higher capacity cost but lower energy costs in the tail years.

Figure 2.8-21 shows the RESA impact of this added wind and solar PV in Alternative Plan B3. Solar PV has a minor impact on the RESA balance.

Figure 2.8-19 System Cost Delta: B3 vs. Least-Cost Baseline Case

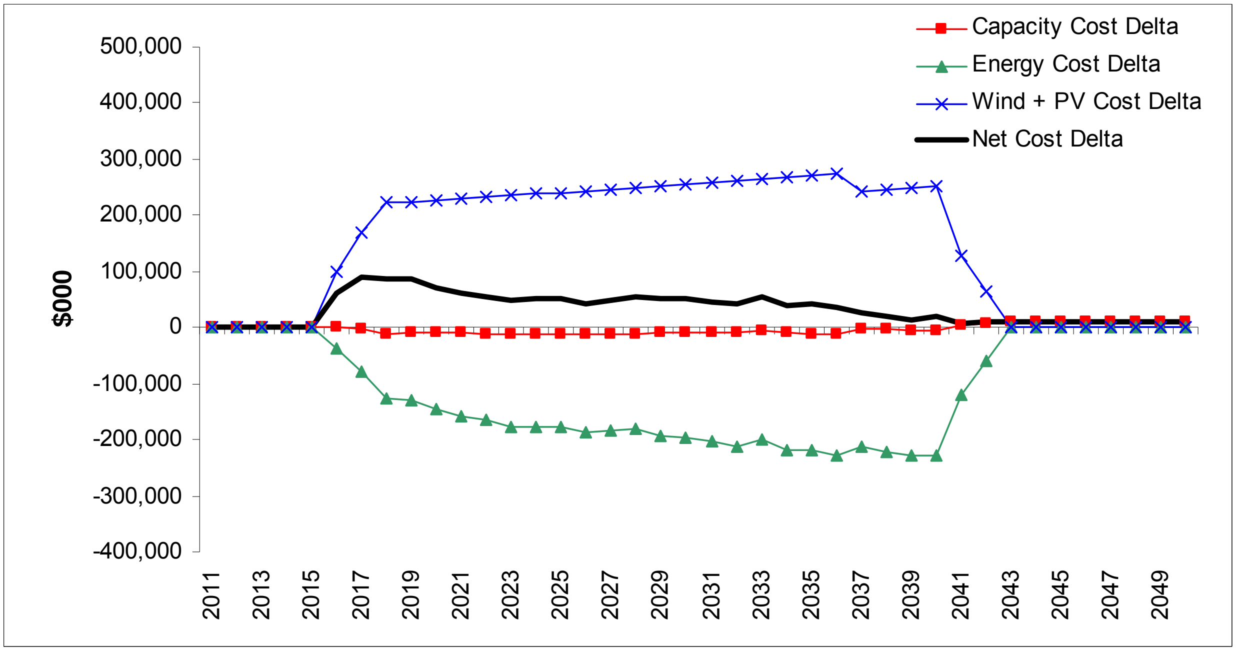


Figure 2.8-20 System Cost Delta: B3 vs. B2

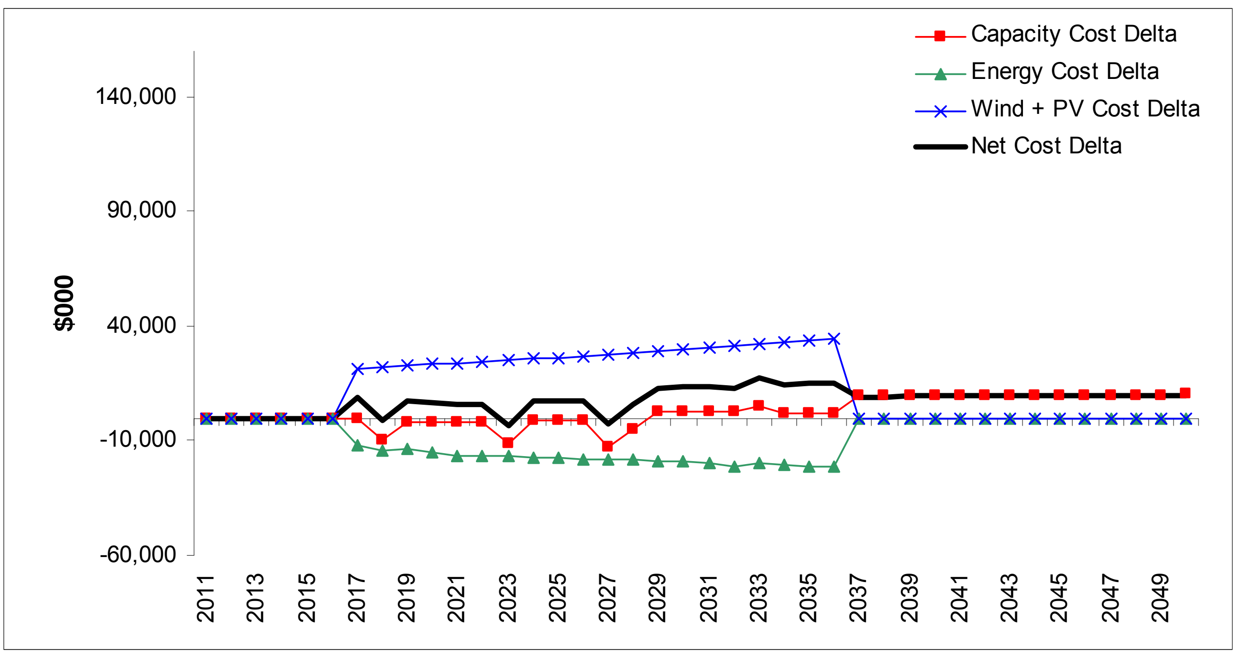
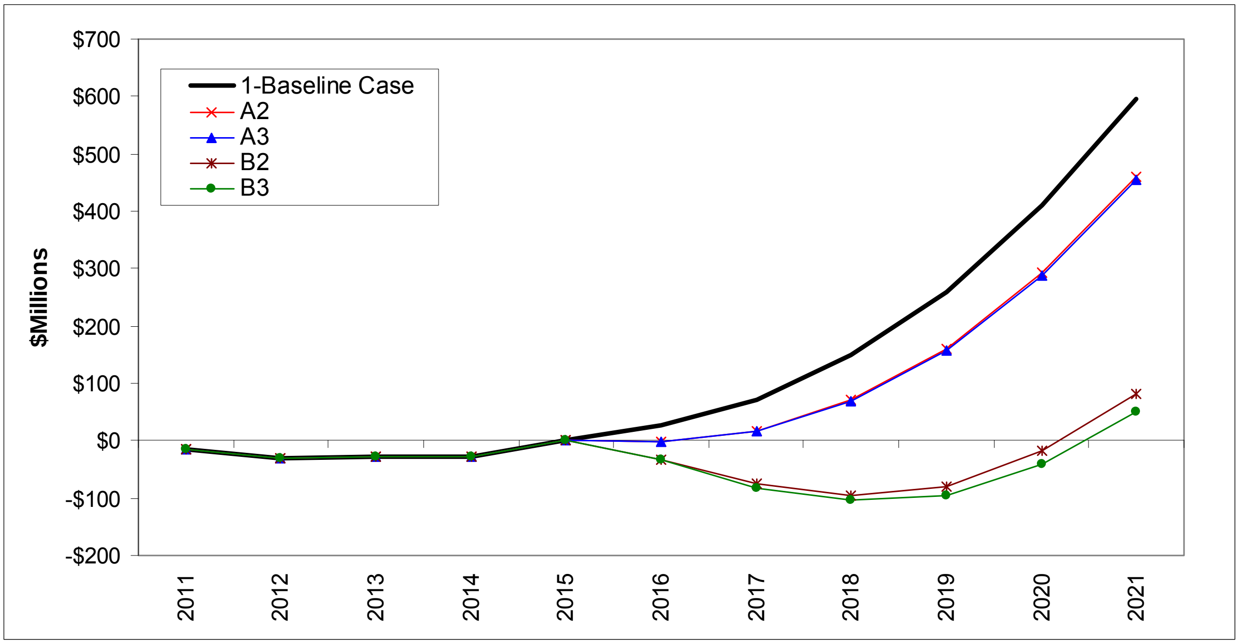


Figure 2.8-21 RESA Impact of Alternative Plan B3



Alternative Plan B4

Alternative plan B4 adds a 100 MW Section 123 battery in 2018 to the 800 MW of non-PTC wind plus 100 MW of solar PV added in Alternative Plan B3. Table 2.8-16 shows the impact of the addition on meeting the RAP resource need.

Table 2.8-16 Alternative Plan B4

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
B4							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind					25	63	100
Utility Scale PV						55	55
Total Renewables	0	0	0	0	25	118	155
Section 123 Resources							
Small storage (batteries)							100
Solar Thermal with Storage							
Total Section 123 Resources	0	0	0	0	0	0	100
Other Resources							
Seasonal Purchase							
Generic Combustion Turbine							173
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	0	173
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(190)**	**(58)**	**(136)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.

[2] All values are shown as the summer accredited capacity

Figure 2.8-22 shows the cost impact of Alternative Plan B4 versus the least-cost baseline case. The net impact is that Alternate Plan B4 is $672 million PVRR higher cost than the least-cost baseline case and $184 million PVRR higher cost than Alternate Plan B3. Figure 2.8-23 shows the annual system cost impact of the battery alone by comparing it against Alternative Plan B3. The battery addition is not a renewable energy resource but is considered a Section 123 resource. Therefore, it has no impact on the RESA balance.

Figure 2.8-22 System Cost Delta: B4 vs. Least-Cost Baseline Case

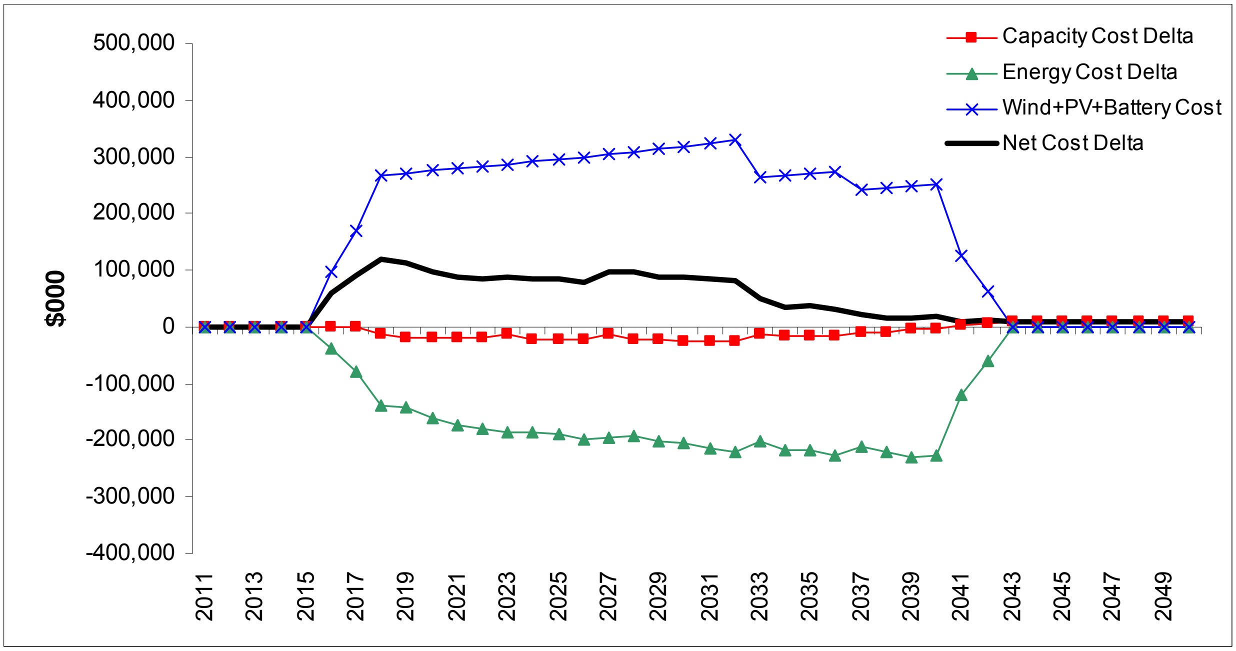
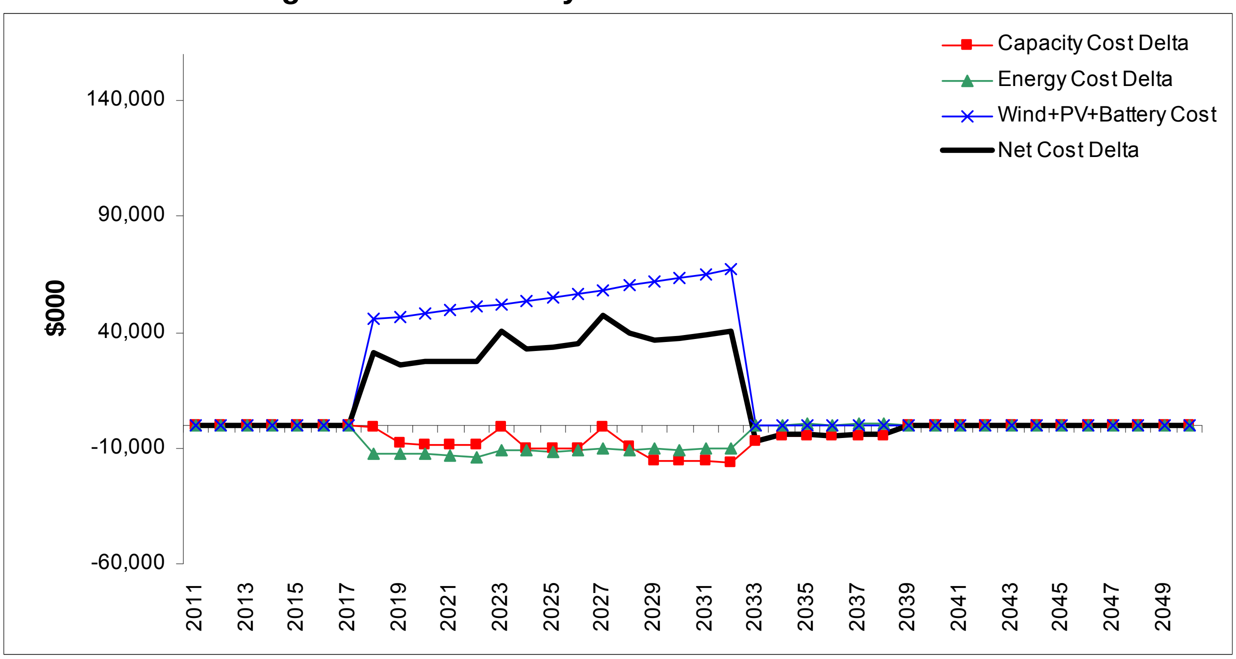


Figure 2.8-23 System Cost Delta: B4 vs. B3



Alternative Plan B5

Alternative plan B5 adds a 125 MW section 123 solar thermal with storage in 2018 to the 800 MW of non-PTC wind plus 100 MW of solar PV added in Alternative Plan B3. The solar thermal with storage resource is assumed to be eligible for the 10% ITC.

Table 2.8-17 shows the impact of the addition on meeting the RAP resource need. Again excess capacity is credited with the capacity cost of a combustion turbine as explained earlier.

Table 2.8-17 Alternative Plan B5 Loads and Resources

Starting Resource Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(165)**	**59**	**292**
A3							
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Non-Section 123 Renewables							
Wind					25	63	100
Utility Scale PV						55	55
Total Renewables	0	0	0	0	25	118	155
Section 123 Resources							
Small storage (batteries)							
Solar Thermal with Storage							125
Total Section 123 Resources	0	0	0	0	0	0	125
Other Resources							
Seasonal Purchase							
Generic Combustion Turbine							173
Generic Combined Cycle							
Total Other Resources	0	0	0	0	0	0	173
Total Remaining Need[1]	**(700)**	**(397)**	**(255)**	**(219)**	**(190)**	**(58)**	**(161)**

[1] Positive number means there is a resource need. Negative means portfolio has excess capacity.
[2] All values are shown as the summer accredited capacity

Figure 2.8-24 shows the cost impact of Alternative Plan B5 versus the baseline case. Similarly, Figure 2.8-25 shows the annual system cost impact of the solar thermal with storage alone by comparing it against Alternative Plan B3. The net impact is that Alternative Plan is $881 million PVRR higher cost than the baseline case and $393 million PVRR higher cost than Alternative Plan B3. The solar thermal with storage resource added is a renewable energy resource but is also a Section 123 Resource. Therefore, it has no impact on the RESA balance.

Figure 2.8-24 System Cost Delta: B5 vs. Least-Cost Baseline Case

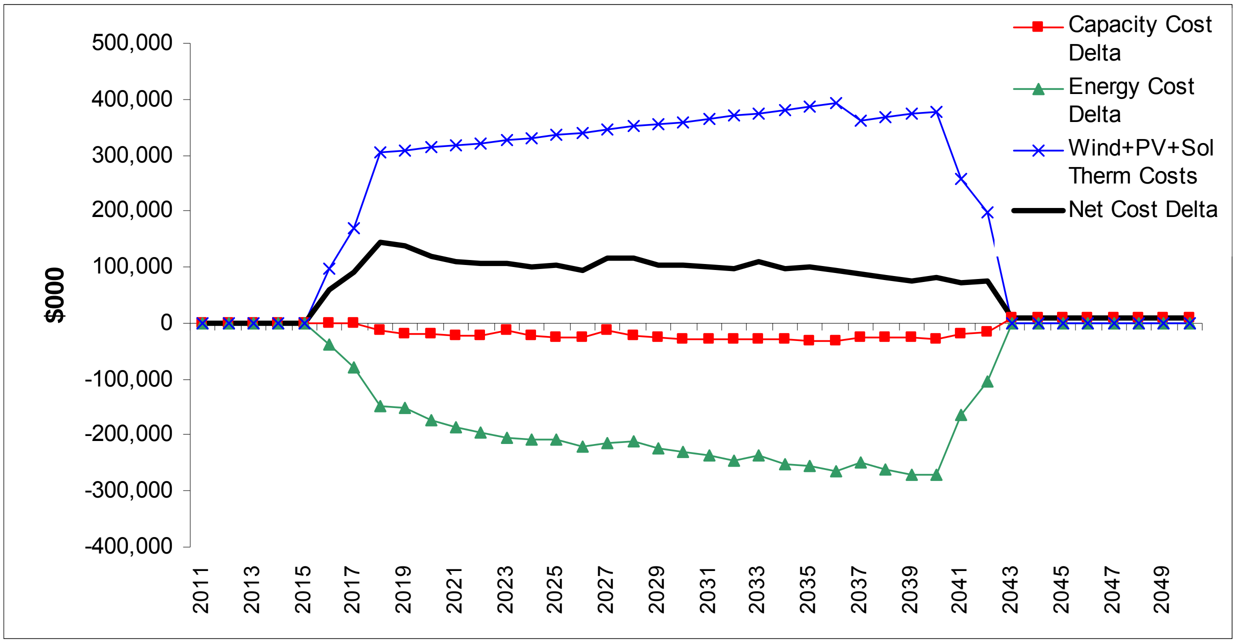
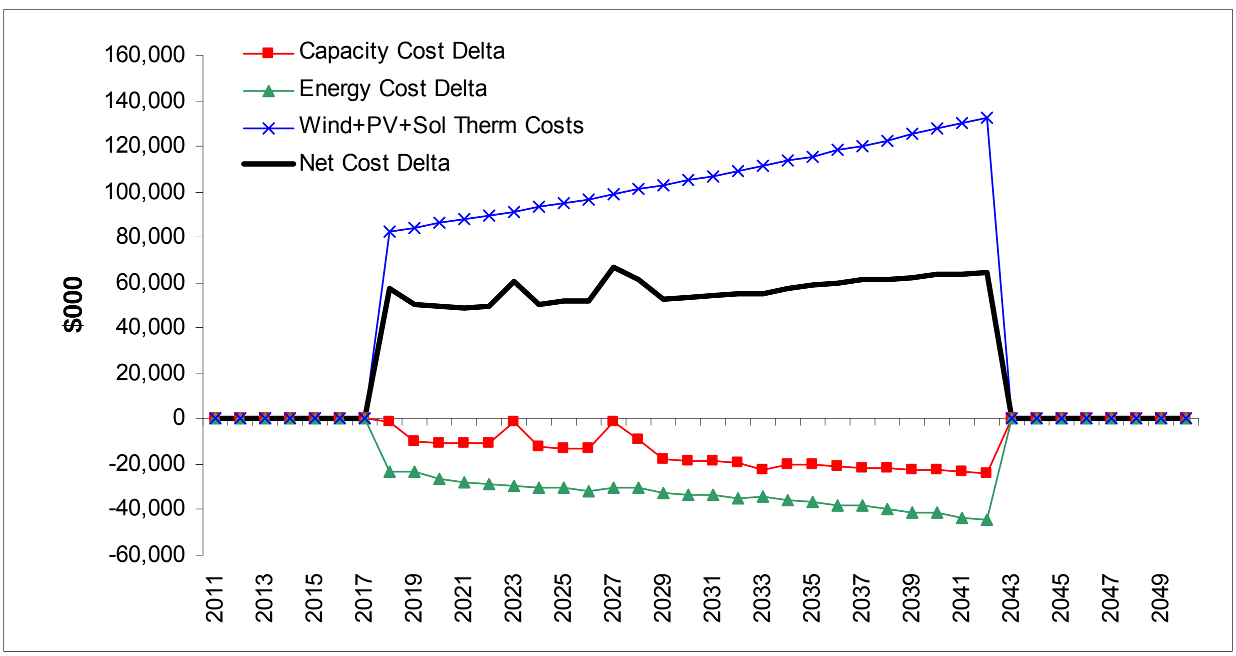


Figure 2.8-25 System Cost Delta: B5 vs. B3



b. Sensitivity Analyses of Alternative Plans

Sensitivity analyses of the alternative plans were completed on several key assumptions. Descriptions of the how the sensitivities are included below. Attachment 2.8-3 shows net annual system cost deltas for the alternative plans under different sensitivities.

The sensitivities include:

1) *Low and High Sales Forecasts* – for this sensitivity, the entire methodology described above was repeated under a forecast of lower future electric sales and again under a forecast of higher future electric sales. The high and low forecasts are described in more detail in Section 2.4. For the low forecast, a low baseline case expansion plan was developed. The resources beyond the RAP in this low sales forecast expansion plan were locked down and the resources added during the RAP were allowed float to fill in where needed to meet capacity requirements. The same resources contained in Table 2.8-10 were then included for each alternative plan during the RAP and repriced under the low sales forecast and expansion plan. The same process was followed under the high sales forecast sensitivity.

   Table 2.8-18 below shows the resources chosen in the RAP for the baseline case under low and high sales forecasts. Attachment 2.8-3 contains the expansion plans under the low and high sales forecasts.

Table 2.8-18 Resources Chosen in the RAP for Different Sales Forecasts

Year	Low Sales	Starting Sales	High Sales
2012			
2013			
2014			
2015			2 CTs
2016			
2017		Seasonal purchase	2 CTs
2018		2 CTs	1 2x1 CC

2) *Low and high gas forecasts* – for this sensitivity, all generic resources through the entire Planning Period in each alternative plan were locked down and the plan PVRRs were recalculated under different forecasts of natural gas prices. The high and low gas forecasts used in this sensitivity are described in more detail in Attachment 2.8-1.

3) *CO_2 Forecasts* – Three forecasts for a CO_2 proxy price were examined in this sensitivity. Similar to the gas forecast sensitivities, all resources through the entire Planning Period in each alternative plan were locked down and the PVRR of each plan is recalculated under different forecasts of CO_2 proxy costs. The CO_2 forecasts are explained in more detail in Attachment 2.8-1.

4) *Wind PTC Extension* – For alternative plans that include non-PTC priced wind, all generic wind added within the RAP is re-priced at a lower price to reflect an extension of the PTC. Again, all resources through the entire Planning Period in each alternative plan were locked down and Strategist recalculated each plan's PVRR. Wind resources added beyond the RAP were kept at non-PTC priced wind prices. The pricing for the non-wind and wind is detailed in the Attachment 2.8-1.

5) *Solar PV ITC* – For alternative plans that include solar PV during the RAP, it's assumed that the solar PV added will be eligible for the 30% ITC which expires at the end of 2016 (therefore the solar PV plant is assumed to be in-service by 12/31/2016). If a solar PV facility misses the 30% ITC deadline, it will still be eligible for the 10% ITC. For this sensitivity, the prices for solar PV added during the RAP are replaced with a higher price to reflect a 10% ITC. Again, all resources through the entire planning period in each alternative plan were locked down and Strategist recalculated the plan PVRR with the 10% ITC pricing. Solar added past the RAP were all assumed to qualify for the 10% ITC. The pricing for the 30% ITC and 10% ITC is detailed in Attachment 2.8-1.

6) *Solar Thermal with Storage ITC* – For alternative plans that include solar thermal with storage during the RAP, it's assumed that the solar thermal added will be eligible for the 10% ITC since it's not expected that a solar thermal with storage facility could be successfully built before the 12/31/2016 expiration date for the 30% ITC. If a solar thermal facility bid in Phase 2 does qualify for the 30% ITC (either by having an in-service date before the end of 2016 or by extension of the 30% ITC), it may be lower priced. For this sensitivity, the prices for solar thermal resources added during the RAP are replaced with the lower 30% ITC priced solar thermal. Again, all resources through the entire Planning Period in each alternative plan were locked down and Strategist re-priced the alternative plans.

Attachment 2.8-1 Modeling Assumptions

1. Capital Structure and Discount Rate

The capital structure and discount rate is the same as that used in the December, 2010 Calpine filing (CPUC Docket No. 10A-327E) as well as that used in Clean Air-Clean Jobs Act analysis (CPUC Docket No. 10M-245E). The rates shown in Table 1 are used to calculate the capital revenue requirements of generic resources. The after tax WACC of 7.609% is also used as the discount rate to determine the present value of revenue requirements. The capital structure and discount rate will be updated for the Phase 2 bid evaluation.

Attachment 2.8-1 Table 1 - Capital Structure

December 31, 2010 Forecast		Public Service of Colorado		
		Electric	before tax	after tax
Ratios Based on Cash Forecast	Cap. Structure	Allowed Return (1)	Elec. WACC	Elec. WACC
Long-Term Debt	42.90%	6.07%	2.603%	1.613%
Common Equity	57.10%	10.50%	5.996%	5.996%
Total Capitalization	100.00%		8.598%	7.609%
Income Tax Rate	38.01%			

(1) Long-Term Debt is from PSCo Forecast Cost of Debt at December 31, 2010.
Common Equity is Last Authorized Return per Docket No. 09AL-299E & Decision No. C09-1446

2. Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of the latest market information (New York Mercantile Exchange ("NYMEX") futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates ("CERA") and Petroleum Industry Research Associates ("PIRA"). The four sources are combined as a simple average to develop the composite forecast. Data from the various sources may not extend through the end of the modeling period (i.e. NYMEX futures currently run through 2023). As the source data ends, the latest value is escalated at a GDP/inflation proxy rate to extend the forecast through the end of the modeling period.

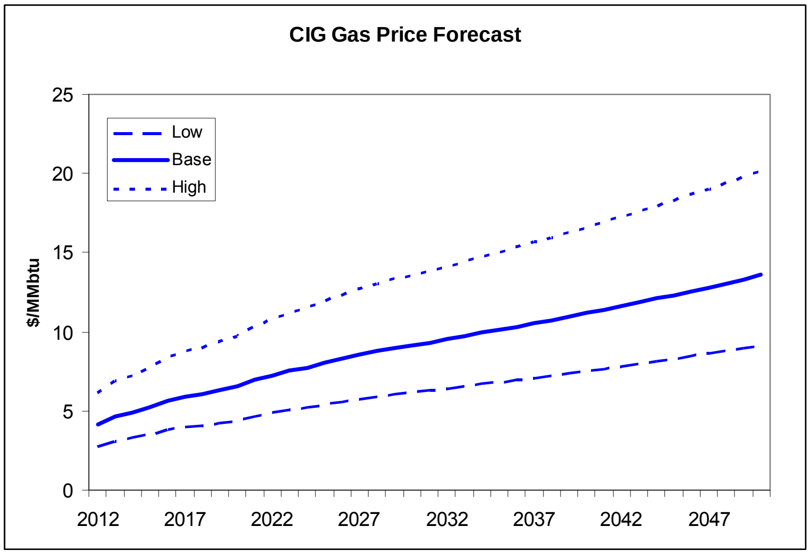
For the basis differentials to Henry Hub of the various regional gas hubs needed for the analysis, the settlement price for the ICE-traded basis swap for the relevant hub is used. The last reported year's profile is extended through the modeling period.

Detailed information regarding the three forecasting services can be found on their respective websites:

- PIRA: www.pira.com
- CERA: www.cera.com
- Wood Mackenzie: www.woodmacresearch.com

High and low gas price sensitivities were run in Phase 1 and will be run in Phase 2. The high and low sensitivities are based on 1 standard deviation above and below the mean.

Attachment 2.8-1 Figure 1



3. Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted ("FL&U") for all of the pipelines the gas flows through from the CIG Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and is at the price of gas commodity being delivered to the plant. A balancing fee of $0.0494 per MMBtu is also added to all generation resources not directly connected to the Colorado Interstate Gas High Plains Pipeline system. Gas transportation costs will be updated for the Phase 2 evaluation. Application of these costs in the Phase 2 evaluation is described in Section 2.9.

4. Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer. Gas demand charges will be updated for the Phase 2 evaluation. Application of these costs in the Phase 2 evaluation is described in Attachment 2.9-1.

5. Market Prices

In addition to resources that exist within Colorado, the Company has access to markets located outside its service territory. External markets include Craig, 4-Corners and SPP and the Southwest Power Pool through the Lamar tie.

Market power prices are developed using a blend of market information from the Intercontinental Exchange ("ICE") for near-term prices and long-term fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Regional prices relevant to Public Service are not generally available publicly; therefore regional prices used for modeling are based on Palo Verde forward prices, where publicly available price information exists, plus a price differential. Regional price differentials are developed using 1) historical relationships between Palo Verde and the regional hub and 2) fundamentally based forecasts where available. Longer term prices at Palo Verde are based on the average of the implied heat rates from the Wood Mackenzie, CERA and PIRA forecasts multiplied by the natural gas 4-Source blend. Data from the various sources may not extend through the end of the modeling period. As the source data ends, implied heat rates from the last year of each forecast are carried forward through the end of the modeling period.

Detailed information regarding the three forecasting services can be found on their respective websites:

- PIRA: www.pira.com
- CERA: www.cera.com
- Wood Mackenzie: www.woodmacresearch.com

6. Gas Price Volatility Mitigation ("GPVM") Adder

A GPVM Adder is added to the base natural gas forecast to account for potential deviations in the future price of natural gas for use in evaluating the total cost of a natural gas fired generating facility in the bid evaluation process. The Company is using the average cost of "at the money" NYMEX call option covering the 10 year period starting in 2012 as the proxy for a GPVM Adder. The modeling of alternative plans in Phase 1 used $0.86/MMbtu. The current GPVM estimate is $0.91/Dth (~$0.91/MMbtu). The GPVM will be updated for the Phase 2 evaluation. The GPVM adder is assigned to gas volumes not under a fixed price contract for the entire planning period.

7. Coal Price Forecasts

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed by averaging price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent RFP responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control and dust suppressant, as required. The coal price forecasts will be updated for the Phase 2 evaluation.

8. Reserve Margin

16.3% based on the “Analysis of ‘Loss of Load Probability’ (LOLP) at various Planning Reserve Margins” completed by Ventyx and filed with the commission in December, 2008. The reserve margin is 16.3% for all years. It will not be updated for the Phase 2 evaluation.

9. Surplus Capacity Credit

Starting in year 2011, resource portfolios with firm generation capacity in excess of the planning reserve margin was credited $2.79/kw-mo escalating at inflation, up to an excess of 500 MW in the Phase 1 alternative plan analysis. The surplus capacity credit price was based on bids received by SPS for seasonal capacity for the 2011 summer season. The credit was applied during the four summer months of June through September through 2018. Past 2018, the credit was applied for all twelve months of each year and was priced at the avoided capacity cost of a generic combustion turbine. The surplus capacity credit price to be applied in the Phase 2 evaluation beyond the RAP will be updated. The Company may perform sensitivities in Phase 2 to more fully understand its impact on the bid portfolio analysis.

10. Seasonal Capacity Purchases

The WECC anticipates that there will be excess capacity available in the WECC area until around 2018. Seasonal capacity purchases are applied during the summer months of June through September. For the alternative plan evaluation in Phase 1, up to 85 MW of seasonal capacity was assumed to be available for purchase at a price of $2.79/kw-mo escalating at inflation. The seasonal capacity price was determined from bids received by Southwestern Public Service Company for capacity for the 2011 summer season. In Phase 1 modeling, past 2017, no seasonal capacity was assumed to be available for purchase.

11. CO_2 Price Forecasts

Four CO_2 price forecasts were used in the analysis of the baseline case and alternative plans.

a) $0/ton CO_2
b) 3-Source Blend
c) 3-Source Blend with low escalation
d) Early CO_2

<u>a. $0/ton CO_2</u>

The starting assumption placed no cost on CO_2 emissions.

<u>b. and c. - 3-Source Blend Sensitivities.</u>

Two separate CO_2 proxy sensitivities were developed using a blend of three long-term fundamentally-based CO_2 emissions price forecasts from Wood Mackenzie, CERA and PIRA. The three sources were combined as a simple average to develop the composite forecast. Data from the various sources may not have extended through the end of the modeling period. Individual forecasts were extended so that each has common term ending in the latest year of any of the three services (currently 2035). Individual forecast were extended to this point using the CO_2 price escalation rate from the last year of each forecast. Beyond this common ending period, the average value was escalated at one of two annual rates to extend the forecast through the end of the modeling period:

1. Gross Domestic Product/inflation proxy rate
2. The average CO_2 price escalation rate from the last year of common ending period which is generally higher than inflation to account for tightening emission standards over time.

The two 3-Source CO_2 sensitivities differ only in the terminal escalation rates listed above.

Detailed information regarding the three forecasting services can be found on their respective websites:

- PIRA: www.pira.com
- CERA: www.cera.com
- Wood Mackenzie: www.woodmacresearch.com

3-Source Blend CO_2 - 3-source blend of the CO_2 forecasts from PIRA, CERA and Wood Mackenzie that continues to escalate at the trended escalation rate into the future.

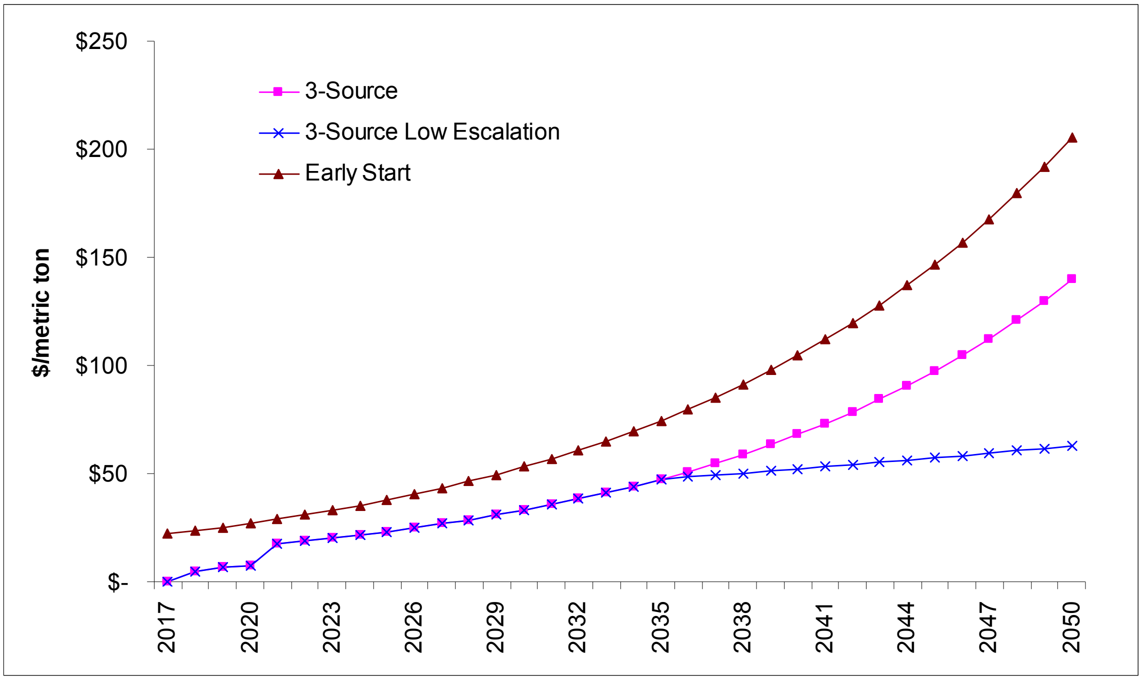
3-Source Blend with Low Escalation CO_2 - 3-source blend of the CO_2 forecasts from PIRA, CERA and Wood Mackenzie that escalates at a lower escalation rate after a period of time.

d. Early CO_2

The fourth CO_2 sensitivity assumed an early CO_2 starting date of 2017 priced at \$20/ton CO_2 and escalating at 7% annually.

Attachment 2.8-1 Figure 2 shows the annual CO_2 prices for the different CO_2 sensitivities.

Attachment 2.8-1 Figure 2 - CO_2 Sensitivity Prices



12. Construction Escalation Rate

Three construction escalation forecasts were developed based on the long-term forecasts from Global Insight Power Planner Second Quarter 2011. Construction escalation is assumed to be 2.8% per year from 2011-2022 and 2.1% from 2023-2050. These rates were used rather than a simple average rate through the entire planning period to reflect that the current expectation is that escalation on construction is expected to be higher during the RAP than a long-term average. The construction escalation rate will be updated for the Phase 2 evaluation. In addition, high and low construction escalation rate sensitivities will be included in the portfolio analysis in Phase 2.

13. Inflation Rates

The inflation rates are developed based on the long-term forecasts from Global Insight of labor and non-labor inflation rates.

- Variable O&M inflation rate - 25% labor inflation and 75% non-labor inflation – 1.55%
- Fixed O&M inflation rate - 100% labor inflation and 0% non-labor inflation – 2.85%
- General inflation – 40% labor inflation and 60% non-labor inflation – 1.78%

The inflation rates will be updated for the Phase 2 evaluation.

14. Demand Side Management Forecasts

The DSM forecast in the load forecast meets 10A-554EG approved goals (CPUC Decision No. C11-0442) through 2015. The forecasted achievements for years beyond 2015 were held at 411 GWh annually. The demand side management forecast will be updated for the Phase 2 evaluation as part of the load forecast update.

15. Transmission Delivery Costs

With the exception of the generic 2x1 combined cycle and baseload plants, no transmission delivery costs were assumed for the Phase 1 generic resources.
Resources less than 500 MW were assumed to be built in locations with sufficient existing transmission capability. The Baseload and 2x1 combined cycle plants were assigned prorated transmission upgrade costs based on SB100 project estimated costs for Missile Site, Midway-Waterton and Smoky Hill SB100 projects.

In Phase 2 of the ERP, the Company will allocate or assign transmission delivery costs on a pro-rata share of transmission upgrades needed for each individual resource bid into Phase 2. The Company will not assign transmission delivery costs to projects that will utilize existing transmission capacity or that will utilize transmission projects for which the Company has been granted a Certificate of Convenience and Necessity for at the time of the bid evaluation. Because Commission Decisions granting a CPCN for the San Luis Valley – Calumet – Comanche transmission line have been appealed to the state courts, bids that are dependent upon the construction of that new transmission facility will be assigned incremental interconnection and network upgrade costs.

16. Interconnection Costs

In Phase 1, estimates of interconnection costs of the generic resources were included in the capital cost estimates. In Phase 2 of the ERP, the Company will estimate and assign Company-owned, Company funded interconnection costs for upgrades needed for each proposed generation facility. Interconnection costs estimates will be developed for each individual Company proposal and bid in Phase 2.

17. Effective Load Carrying Capability ("ELCC") Capacity Credit for Wind Resources

Existing wind facilities and new wind proposals were given a capacity credit in the evaluation process equal to 12.5% of their nameplate rating, which was derived from the Company's Effective Load Carrying Capability study completed in March, 2007. The wind capacity credit for Phase 2 will be 12.5%

18. Effective Load Carrying Capability ("ELCC") Capacity Credit for Utility Scale Solar PV Resources

Utility scale generic solar PV additions used in modeling the alternative plans in Phase 1 were given a capacity credit equal to 55% of the AC nameplate capacity, which is representative of a high-efficiency, tracking system located in the San Luis Valley. For Phase 2, bids for utility scale solar PV bids will be given a capacity credit in portfolio modeling consistent with the Company's most recent Effective Load Carrying Capability study at the time of the analyses.

19. Resource Acquisition Period

"Resource acquisition period" means the first six to ten years of the planning period, in which the utility acquires specific resources to meet projected electric system demand and energy requirements. The resource acquisition period begins from the date the utility files its plan with the Commission. For the 2011 plan, the resource acquisition period will be from October 31st, 2011 through October 31st, 2018.

20. Planning Period

"Planning period" means the future period for which a utility develops its plan, and the period, over which net present value of revenue requirements for resources are calculated. For purposes of this rule, the planning period is twenty to forty years and begins from the date the utility files its plan with the Commission. The planning period is 40 years from 2011 through 2050.

21. SO_2 Effluent Costs and Allocations

SO_2 is controlled through the Acid Rain program in Colorado. The Company has excess SO_2 allowances because of the use of low sulfur coal and scrubber retrofits at Hayden and the VERP units. Therefore, the Company does not anticipate that it will have to purchase any allowances for SO_2 under current or reasonably foreseeable legislation. In addition, Acid Rain allowances are trading for less than $1.00 per ton so the value of the excess allowances that the Company owns is very little. Therefore, the Company assigns no effluent costs or allocations to SO_2. SO_2 effluent $/ton costs will zero in Phase 2 unless a major change in legislation occurs by Phase 2 of the 2011 ERP.

22. NO_x Effluent Costs and Allocations

There is no trading program for sources of NO_x in Colorado; therefore, no $/ton cost is applied to NO_x emissions. The primary programs that reduce NO_x are regional haze, through the Best Available Retrofit Technology program or to achieve further reasonable progress towards long term visibility goals in Class I areas like national parks and wilderness areas. The Denver ozone State Implementation Plan ("SIP") is also another driver for NO_x reductions. As a result, the costs of NO_x reductions are embedded in capital and operating costs of the resources included in the SIP (e.g. the Selective Catalytic Reduction additions to Pawnee and Hayden). NO_x effluent $/ton costs will not be updated or applied in

Phase 2 unless a major change in legislation occurs by Phase 2 of the 2011 ERP.

23. Mercury Effluent Costs and Allocations

Mercury is also controlled as a command and control rule through the Colorado Mercury Rule and new proposed EPA rules for the control of hazardous air pollutants through installation of Maximum Achievable Controls Technology. Therefore, there is no cap and trade for mercury either and effluent costs and allocations were assigned a zero cost in the Phase 1 alternative plan analysis. As with SO2 and NOx, costs associated with controlling these emissions were captured in the resource costs. Mercury effluent costs will not be updated or applied in Phase 2 unless a major change in legislation occurs by Phase 2 of the 2011 ERP

24. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled was consistent with the Company's Rocky Mountain Reserve Group (RMRG) requirements. The cost of spinning was estimated in the Strategist model by assigning a spin requirement and the spinning capability of each resource. The spin requirement will not be updated in Phase 2

25. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at an arbitrary cost ($500/MWh) above the cost of the most expensive resource. Emergency energy costs occur only in rare instances. The emergency energy costs will not be updated in Phase 2.

26. Dump Energy / Wind Curtailment Costs

Estimates of wind curtailment costs were represented in the Strategist model by the "dump energy" variable. Dump energy occurs whenever generation cannot be reduced enough to balance with load, a situation that occurs on the Public Service system primarily due to the non-dispatchable nature of wind generation resources. When wind energy is curtailed in order to maintain the balance between load and generation, in many instances the Company pays the wind generator the cost of lost production tax credits (PTC). Payment for lost production tax credits were accounted for by pricing dump energy at the grossed-up PTC price (PTC/(1-tax rate)) through 2022 (10 years after expiration of the PTC on 12/31/2012). Curtailed wind costs will be updated, if necessary, in Phase 2.

27. Wind Integration Costs

Wind integration costs were priced based upon the results of the 2 GW and 3GW Wind Integration Cost Study (See Attachment 2.13-1). Wind integration costs contain three components:

1) Power supply integration costs
2) Regulation integration costs
3) Gas storage integration costs

28. Wind Induced Coal Plant Cycling Costs

Wind induced coal cycling costs were priced based upon the results of the *Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment for Public Service Company of Colorado*[29] completed in August, 2011 (See Attachment 2.12-1). The study addressed two cost items: coal plant cycling costs and wind curtailment costs. Wind curtailment costs are estimated within the Strategist model and therefore this component of cycling costs was not added to the price of wind. The coal plant cycling cost estimates from the study are however added as an additional cost to wind generation.

29. Solar Integration Costs

Solar integration costs were priced upon the results of a solar integration study completed in 2009. Similar to wind, solar is must-take energy that is dependent upon the instantaneous solar resource available. As such it is intermittent (i.e., variable) and non-dispatchable. For Phase 2, the solar integration costs will be based on the results of the Company's most recent solar integration cost study.

30. Owned Unit Modeled Operating Characteristics and Costs

Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of operating and cost inputs for each company owned resource.

a. Maximum Capacity
b. Minimum Capacity Rating
c. Seasonal Deration
d. Heat Rate Profiles
e. Variable O&M
f. Fixed O&M
g. Maintenance Schedule
h. Forced Outage Rate
i. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
j. Contribution to spinning reserve
k. Fuel prices
l. Fuel delivery charges

[29] See Section 2.12 of the technical appendix

31. Thermal PPA Operating Characteristics and Costs

Power Purchase Agreements are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each thermal purchase power contract.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

32. Renewable Energy PPA Operating Characteristics and Costs

Power Purchase Agreements are modeled based upon their tested operating characteristics and contracted costs. Below is a list of operating and cost inputs for each renewable energy purchase power contract.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity Payments
g. Energy Payments
h. Integration Costs
i. Emission rates for SO_2, NO_x, CO_2, Mercury and PM if applicable

Attachment 2.8-1 Table 2

Item	Starting Assumption	Updated in Phase 2	Sensitivity	
			Phase 1	Phase 2
Capital Structure	See Attachment 2.8-1 Debt/Equity Ratio: 42.9%/57.1% Debt Rate: 6.07% Equity Rate: 10.5%	YES	None	None
CO_2 Price Forecasts	$0/ton	NO	1) 3-Source blend 2) 3-Source blend with low esc 3) Early start CO2	1) 3-Source blend 2) 3-Source blend with low esc 3) Early start CO2
Coal Cycling Costs	Varies by amount of wind and energy storage on system	YES, for levels of wind and energy storage	None	None
Coal Price Forecasts	See Attachment 2.8-1 Varies by plant	YES	None	None
Coal Price Volatility Mitigation (CPVM) Adder	$0	NO	None	None
Construction Escalation Rate	2.8% for 2011-2022, 2.1% for 2023-2050	YES	None	Low/High Escalation
Dispatchable Generic Resources	See Table 2.8-1	TBD, will assess whether an update is appropriate	None	None
DSM Forecast	10A-554EG approved goals (Dec. No. C11-0442) through 2015. The goals 2016+ are held at 2015 approved goal of 411 GWh.	YES	None	None
Dump Energy Costs	Grossed-up PTC price from 2011 through 2022	YES	None	None
ELCC Capacity Credit for Utility Scale Solar PV Resources	55% of AC nameplate	Will be consistent with most recent ELCC study at time of bid evaluation	None	None
ELCC Capacity Credit for Wind Resources	12.5% of nameplate capacity	NO	None	None

Attachment 2.8-1 Table 2 (continued)

Item	Starting Assumption	Updated in Phase 2	Sensitivity	
			Phase 1	Phase 2
Emergency Energy Costs	$500/MWh	NO	None	None
Federal Tax Rate	35%	NO	None	None
Fixed O&M Inflation	2.85%	YES	None	None
Gas Demand Charges	See Attachment 2.8-1 Varies by resource	YES	None	None
Gas Price Forecasts	See Attachment 2.8-1	YES	Low/High	Low/High
Gas Price Volatility Mitigation (GPVM) Adder	$0.86/Dth for all years	YES	None	None
Gas Transportation Costs	See Attachment 2.8-1 Varies by plant	YES	None	None
General Inflation	1.78%	YES	None	None
Interconnection Costs Applied to Bids	Varies by resource	YES, will be applied to bids as required	None	None
Market Prices	See attachment 2.8-1 Varies by location	YES	Adjusted for gas price and CO2 price sensitivities	Adjusted for gas price and CO2 price sensitivities
Mercury Effluent Costs and Allocations	$0/lb	NO	None	None
NOx Effluent Costs and Allocations	$0/ton	NO	None	None
Owned unit modeled retirement dates	See Attachment 2.4-4	YES	None	None
Owned unit operating characteristics and costs	Varies by resource	NO, except for Cherokee 4 and Arapahoe 4	None	None
Planning Period	2011-2050	NO	None	None
Power Purchase Contract operating characteristics and costs	Varies by contract	YES, for material changes	None	None
Renewable Energy Power Purchase Contracts	Varies by contract	YES, for material changes	None	None
Renewable Generic Resources	See Table 2.8-2	TBD, will assess whether an update is appropriate	None	None
Reserve Margin	16.30%	NO	None	None

Attachment 2.8-1 Table 2 (continued)

Item	Starting Assumption	Updated in Phase 2	Sensitivity	
			Phase 1	Phase 2
Resource Acquisition Period	October 31st, 2011 through October 31st, 2018	NO	None	None
Sales forecast	See Section 2.6	YES	Low/High	None
Seasonal Capacity Purchases	$2.79/kw-mo for 4 months for years 2011-2017 up to 85 MW.	YES	None	None
SO_2 Effluent Costs and Allocations	$0/ton	NO	None	None
Solar Integration Costs	2009 Solar Integration Study	YES, for gas prices	Adjusted under gas price sensitivities	Adjusted under gas price sensitivities
Spinning Reserve Requirement	Company's Rocky Mountain Reserve Group (RMRG) requirements	NO	None	None
State Tax Rate	4.63%	NO	None	None
Surplus Capacity Credit	$2.79/kw-mo for 4 months for years 2011-2018, generic CT $/kw-mo for 12 months for years 2019-2050. All years allowed up to 500 MW.	YES	None	TBD
Transmission Delivery Costs	$28/kw-yr for baseload and 2x1 CC generics $0 for all other generics	YES, will be applied to bids as required	None	None
Variable O&M Inflation	1.55%	YES	None	None
WACC	7.609%	Only if material change	None	None
Wind Integration Costs	Varies by amount of wind and energy storage on system and gas prices	YES, for levels of wind, energy storage and gas prices	Adjusted under gas price sensitivities	Adjusted under gas price sensitivities

Attachment 2.8-2 Strategist Modeled Emissions

Projected Emission Rates for Generic Resources[30]

	SO_2 (lb/MWh)	NO_x (lb/MWh)	PM (lb/MWh)	Mercury (lb/Million MWh)	CO_2 (lb/MWh)
GENERIC RESOURCES					
RAP 2x1 Combined Cycle	0.032	0.131	0.034	0	828
RAP 1x1 Combined Cycle	0.040	0.115	0.069	0	828
RAP Combustion Turbine	0.064	0.342	0.052	0	1322
Post-RAP Baseload Plant	0.500	0.300	0.152	8	220
Post-RAP 2x1 Combined Cycle	0.035	0.142	0.034	0	903
Post-RAP 1x1 Combined Cycle	0.033	0.118	0.069	0	850
Post-RAP Combustion Turbine	0.064	0.342	0.052	0	1322
Battery	0.000	0.000	0.000	0	0
Wind	0.000	0.000	0.000	0	0
Solar PV	0.000	0.000	0.000	0	0
Solar Thermal	0.000	0.000	0.000	0	0

[30] Existing Company-owned and purchased resource emission rates are confidential.

Annual Projected SO_2 Emissions from Existing Resources

Year	1-Baseline (Tons)	A2 (Tons)	A3 (Tons)	A4 (Tons)	A5 (Tons)	B2 (Tons)	B3 (Tons)	B4 (Tons)	B5 (Tons)
2011	28,099	28,099	28,099	28,099	28,099	28,099	28,099	28,099	28,099
2012	26,536	26,536	26,536	26,536	26,536	26,536	26,536	26,536	26,536
2013	25,091	25,091	25,091	25,091	25,091	25,091	25,091	25,091	25,091
2014	20,235	20,235	20,235	20,235	20,235	20,235	20,235	20,235	20,235
2015	10,968	10,968	10,968	10,968	10,968	10,968	10,968	10,968	10,968
2016	10,239	10,091	10,091	10,091	10,091	9,929	9,929	9,929	9,929
2017	10,086	9,960	9,952	9,952	9,952	9,681	9,650	9,650	9,650
2018	6,982	6,922	6,921	6,932	6,915	6,700	6,688	6,737	6,661
2019	7,207	7,152	7,150	7,158	7,142	6,927	6,913	6,965	6,882
2020	6,799	6,750	6,748	6,755	6,745	6,576	6,566	6,607	6,548
2021	7,089	7,041	7,039	7,048	7,036	6,852	6,840	6,883	6,817
2022	7,283	7,232	7,229	7,237	7,221	7,014	7,000	7,043	6,970
2023	7,005	6,971	6,969	6,973	6,963	6,817	6,806	6,838	6,789
2024	7,189	7,151	7,153	7,158	7,148	6,994	6,983	7,019	6,965
2025	7,174	7,136	7,133	7,139	7,129	6,967	6,957	6,993	6,936
2026	7,077	7,044	7,043	7,047	7,039	6,898	6,888	6,920	6,871
2027	7,090	7,060	7,059	7,062	7,056	6,923	6,916	6,945	6,900
2028	7,270	7,236	7,235	7,239	7,232	7,077	7,067	7,103	7,045
2029	6,789	6,759	6,757	6,762	6,755	6,645	6,637	6,662	6,628
2030	7,005	6,978	6,977	6,980	6,974	6,867	6,859	6,883	6,848
2031	6,347	6,325	6,324	6,326	6,321	6,223	6,217	6,238	6,205
2032	6,084	6,056	6,055	6,058	6,053	5,962	5,953	5,972	5,945
2033	6,248	6,219	6,218	6,218	6,215	6,114	6,108	6,109	6,097
2034	5,399	5,373	5,372	5,372	5,369	5,285	5,281	5,282	5,272
2035	5,325	5,299	5,298	5,298	5,294	5,213	5,209	5,210	5,200
2036	4,572	4,550	4,550	4,550	4,547	4,476	4,472	4,473	4,466
2037	4,081	4,062	4,062	4,062	4,060	4,005	4,005	4,005	3,999
2038	3,692	3,675	3,675	3,675	3,674	3,635	3,635	3,636	3,630
2039	3,841	3,824	3,824	3,824	3,823	3,783	3,783	3,783	3,778
2040	4,008	3,991	3,991	3,991	3,989	3,942	3,942	3,942	3,936
2041	3,731	3,731	3,731	3,731	3,730	3,704	3,704	3,704	3,700
2042	1,421	1,421	1,421	1,421	1,420	1,412	1,411	1,411	1,409
2043	1,535	1,535	1,535	1,535	1,535	1,535	1,534	1,534	1,534
2044	1,539	1,539	1,539	1,539	1,539	1,539	1,539	1,539	1,539
2045	1,421	1,421	1,421	1,421	1,421	1,421	1,420	1,420	1,420
2046	1,536	1,536	1,536	1,536	1,536	1,536	1,535	1,535	1,535
2047	1,535	1,535	1,535	1,535	1,535	1,535	1,534	1,534	1,534
2048	1,270	1,270	1,270	1,270	1,270	1,270	1,269	1,269	1,269
2049	1,523	1,523	1,523	1,523	1,523	1,523	1,522	1,522	1,522
2050	1,528	1,528	1,528	1,528	1,528	1,528	1,527	1,527	1,527

Annual Projected NO_x Emissions from Existing Resources

Year	1-Baseline (Tons)	A2 (Tons)	A3 (Tons)	A4 (Tons)	A5 (Tons)	B2 (Tons)	B3 (Tons)	B4 (Tons)	B5 (Tons)
2011	29,386	29,386	29,386	29,386	29,386	29,386	29,386	29,386	29,386
2012	25,567	25,567	25,567	25,567	25,567	25,567	25,567	25,567	25,567
2013	24,877	24,877	24,877	24,877	24,877	24,877	24,877	24,877	24,877
2014	22,262	22,262	22,262	22,262	22,262	22,262	22,262	22,262	22,262
2015	19,936	19,936	19,936	19,936	19,936	19,936	19,936	19,936	19,936
2016	15,595	15,303	15,303	15,303	15,303	15,006	15,006	15,006	15,006
2017	14,685	14,416	14,395	14,395	14,395	13,872	13,794	13,794	13,794
2018	9,218	9,060	9,049	9,058	9,019	8,556	8,509	8,543	8,418
2019	9,209	9,056	9,045	9,050	9,012	8,563	8,518	8,553	8,433
2020	9,097	8,952	8,942	8,950	8,918	8,504	8,465	8,504	8,391
2021	9,227	9,091	9,081	9,093	9,065	8,641	8,599	8,642	8,526
2022	9,258	9,131	9,121	9,131	9,095	8,681	8,638	8,681	8,561
2023	8,740	8,643	8,635	8,638	8,613	8,301	8,272	8,291	8,213
2024	8,949	8,847	8,845	8,849	8,824	8,510	8,474	8,505	8,416
2025	8,635	8,538	8,528	8,532	8,507	8,199	8,165	8,191	8,106
2026	8,879	8,785	8,777	8,781	8,758	8,454	8,418	8,444	8,360
2027	8,602	8,531	8,525	8,527	8,511	8,273	8,253	8,280	8,211
2028	8,560	8,487	8,482	8,485	8,467	8,217	8,194	8,226	8,146
2029	8,404	8,334	8,328	8,332	8,314	8,096	8,072	8,094	8,040
2030	8,503	8,434	8,428	8,430	8,413	8,205	8,182	8,202	8,147
2031	8,154	8,087	8,082	8,083	8,067	7,863	7,841	7,859	7,804
2032	8,053	7,979	7,973	7,975	7,957	7,750	7,722	7,738	7,685
2033	7,930	7,875	7,871	7,871	7,860	7,689	7,672	7,673	7,644
2034	6,222	6,167	6,163	6,163	6,152	5,999	5,982	5,984	5,955
2035	6,478	6,422	6,418	6,418	6,406	6,251	6,234	6,234	6,205
2036	4,240	4,199	4,195	4,195	4,187	4,087	4,076	4,076	4,058
2037	4,036	3,999	3,999	3,999	3,990	3,895	3,895	3,895	3,875
2038	3,882	3,844	3,844	3,844	3,835	3,740	3,739	3,740	3,719
2039	3,851	3,816	3,816	3,816	3,808	3,722	3,720	3,720	3,700
2040	3,613	3,577	3,577	3,577	3,569	3,484	3,483	3,483	3,463
2041	3,040	3,040	3,040	3,040	3,031	2,974	2,973	2,973	2,953
2042	1,429	1,429	1,429	1,429	1,427	1,415	1,414	1,414	1,409
2043	1,498	1,498	1,498	1,498	1,498	1,498	1,497	1,497	1,497
2044	1,534	1,534	1,534	1,534	1,534	1,534	1,533	1,533	1,533
2045	1,432	1,432	1,432	1,432	1,432	1,432	1,430	1,430	1,430
2046	1,536	1,536	1,536	1,536	1,536	1,536	1,535	1,535	1,535
2047	1,540	1,540	1,540	1,540	1,540	1,540	1,537	1,537	1,537
2048	1,274	1,274	1,274	1,274	1,274	1,274	1,272	1,272	1,272
2049	1,475	1,475	1,475	1,475	1,475	1,475	1,473	1,473	1,473
2050	1,480	1,480	1,480	1,480	1,480	1,480	1,478	1,478	1,478

Annual Projected PM Emissions from Existing Resources

Year	1-Baseline (Tons)	A2 (Tons)	A3 (Tons)	A4 (Tons)	A5 (Tons)	B2 (Tons)	B3 (Tons)	B4 (Tons)	B5 (Tons)
2011	722	722	722	722	722	722	722	722	722
2012	645	645	645	645	645	645	645	645	645
2013	568	568	568	568	568	568	568	568	568
2014	578	578	578	578	578	578	578	578	578
2015	587	587	587	587	587	587	587	587	587
2016	571	557	557	557	557	542	542	542	542
2017	597	581	580	580	580	551	546	546	546
2018	582	569	568	568	565	528	523	524	516
2019	607	593	591	591	588	549	544	544	536
2020	622	607	605	605	602	562	557	557	548
2021	619	603	602	603	599	557	551	552	543
2022	652	637	636	636	632	590	585	586	576
2023	577	565	564	564	561	530	526	524	519
2024	574	563	562	562	559	529	525	525	518
2025	573	563	561	561	558	529	525	524	518
2026	585	574	573	573	570	541	536	536	529
2027	522	514	514	514	512	493	490	490	486
2028	530	523	523	522	521	502	499	500	495
2029	531	524	523	523	521	502	500	500	496
2030	512	505	505	505	503	485	483	483	479
2031	499	492	491	491	489	471	469	469	465
2032	494	487	486	486	484	466	462	462	458
2033	451	446	446	446	444	432	430	430	426
2034	380	374	374	374	372	358	356	356	352
2035	387	381	381	381	379	366	363	363	360
2036	302	297	297	297	295	285	283	283	281
2037	271	267	267	267	265	255	255	255	253
2038	279	275	275	275	273	262	262	262	259
2039	251	246	246	246	245	235	234	234	231
2040	266	262	262	262	260	250	250	250	247
2041	259	259	259	259	257	250	250	250	247
2042	211	211	211	211	211	209	208	208	207
2043	219	219	219	219	219	219	218	218	218
2044	226	226	226	226	226	226	225	225	225
2045	213	213	213	213	213	213	212	212	212
2046	227	227	227	227	227	227	226	226	226
2047	228	228	228	228	228	228	227	227	227
2048	188	188	188	188	188	188	187	187	187
2049	211	211	211	211	211	211	211	211	211
2050	212	212	212	212	212	212	212	212	212

Annual Projected Mercury Emissions from Existing Resources

Year	1-Baseline (lbs)	A2 (lbs)	A3 (lbs)	A4 (lbs)	A5 (lbs)	B2 (lbs)	B3 (lbs)	B4 (lbs)	B5 (lbs)
2011	717	717	717	717	717	717	717	717	717
2012	485	485	485	485	485	485	485	485	485
2013	471	471	471	471	471	471	471	471	471
2014	344	344	344	344	344	344	344	344	344
2015	350	350	350	350	350	350	350	350	350
2016	314	311	311	311	311	307	307	307	307
2017	289	286	286	286	286	280	279	279	279
2018	266	264	264	264	263	256	256	258	255
2019	269	267	267	268	267	260	260	261	259
2020	258	256	256	257	256	251	251	252	250
2021	265	263	263	264	263	258	257	259	257
2022	261	260	260	260	260	253	253	255	252
2023	219	218	218	218	218	213	213	214	213
2024	226	225	225	225	225	220	219	221	219
2025	223	222	222	222	222	217	217	218	216
2026	222	221	221	221	221	216	216	217	216
2027	225	224	224	224	224	220	219	220	219
2028	227	226	226	226	226	221	221	222	220
2029	215	214	214	214	214	210	210	211	210
2030	219	219	219	219	218	215	215	216	215
2031	218	217	217	217	217	214	213	214	213
2032	211	210	210	210	210	207	207	207	206
2033	215	215	214	214	214	211	211	211	210
2034	182	182	181	181	181	179	178	178	178
2035	182	181	181	181	181	178	178	178	178
2036	152	152	152	152	152	149	149	149	149
2037	142	142	142	142	142	140	140	140	139
2038	132	131	131	131	131	130	130	130	130
2039	133	133	133	133	133	131	131	131	131
2040	130	130	130	130	130	128	128	128	128
2041	112	112	112	112	112	112	112	112	111
2042	47	47	47	47	47	47	47	47	47
2043	51	51	51	51	51	51	51	51	51
2044	51	51	51	51	51	51	51	51	51
2045	47	47	47	47	47	47	47	47	47
2046	51	51	51	51	51	51	51	51	51
2047	51	51	51	51	51	51	51	51	51
2048	42	42	42	42	42	42	42	42	42
2049	51	51	51	51	51	51	51	51	51
2050	51	51	51	51	51	51	51	51	51

Annual Projected CO_2 Emissions from Existing Resources

Year	1-Baseline '000 Tons	A2 '000 Tons	A3 '000 Tons	A4 '000 Tons	A5 '000 Tons	B2 '000 Tons	B3 '000 Tons	B4 '000 Tons	B5 '000 Tons
2011	28,963	28,963	28,963	28,963	28,963	28,963	28,963	28,963	28,963
2012	27,549	27,549	27,549	27,549	27,549	27,549	27,549	27,549	27,549
2013	26,727	26,727	26,727	26,727	26,727	26,727	26,727	26,727	26,727
2014	25,960	25,960	25,960	25,960	25,960	25,960	25,960	25,960	25,960
2015	26,526	26,526	26,526	26,526	26,526	26,526	26,526	26,526	26,526
2016	24,908	24,394	24,394	24,394	24,394	23,878	23,878	23,878	23,878
2017	24,758	24,269	24,228	24,228	24,228	23,259	23,095	23,095	23,095
2018	22,316	21,942	21,917	21,944	21,843	20,716	20,594	20,692	20,376
2019	22,838	22,440	22,410	22,427	22,323	21,174	21,042	21,133	20,819
2020	22,549	22,174	22,146	22,166	22,081	20,982	20,861	20,948	20,648
2021	23,131	22,742	22,713	22,746	22,650	21,493	21,368	21,462	21,152
2022	22,768	22,419	22,391	22,414	22,317	21,219	21,102	21,201	20,889
2023	19,925	19,637	19,612	19,618	19,544	18,714	18,637	18,648	18,460
2024	20,366	20,074	20,056	20,063	19,989	19,150	19,044	19,095	18,869
2025	20,128	19,843	19,815	19,822	19,748	18,891	18,785	18,824	18,602
2026	20,350	20,064	20,041	20,050	19,979	19,150	19,042	19,077	18,858
2027	19,189	18,973	18,956	18,958	18,908	18,289	18,217	18,258	18,087
2028	19,284	19,067	19,049	19,053	18,999	18,341	18,262	18,313	18,122
2029	18,801	18,582	18,561	18,567	18,512	17,905	17,833	17,856	17,708
2030	19,066	18,864	18,845	18,849	18,795	18,208	18,131	18,161	18,011
2031	18,377	18,176	18,157	18,155	18,103	17,524	17,448	17,470	17,321
2032	18,030	17,816	17,797	17,800	17,746	17,160	17,077	17,096	16,950
2033	16,994	16,825	16,811	16,811	16,771	16,317	16,257	16,259	16,159
2034	14,909	14,719	14,702	14,702	14,657	14,170	14,100	14,101	13,989
2035	15,006	14,820	14,802	14,802	14,756	14,275	14,207	14,206	14,093
2036	11,828	11,680	11,666	11,666	11,628	11,266	11,215	11,213	11,131
2037	11,263	11,122	11,122	11,122	11,083	10,718	10,716	10,717	10,628
2038	10,769	10,619	10,619	10,619	10,580	10,210	10,208	10,210	10,118
2039	10,866	10,723	10,723	10,723	10,687	10,343	10,339	10,339	10,245
2040	11,171	11,024	11,024	11,024	10,985	10,635	10,633	10,633	10,542
2041	10,692	10,692	10,692	10,692	10,653	10,399	10,396	10,396	10,306
2042	5,400	5,400	5,400	5,400	5,382	5,324	5,321	5,321	5,283
2043	5,436	5,436	5,436	5,436	5,436	5,436	5,432	5,432	5,432
2044	5,736	5,736	5,736	5,736	5,736	5,736	5,733	5,733	5,733
2045	5,403	5,403	5,403	5,403	5,403	5,403	5,398	5,398	5,398
2046	5,757	5,757	5,757	5,757	5,757	5,757	5,752	5,752	5,752
2047	5,784	5,784	5,784	5,784	5,784	5,784	5,776	5,776	5,776
2048	4,797	4,797	4,797	4,797	4,797	4,797	4,792	4,792	4,792
2049	5,429	5,429	5,429	5,429	5,429	5,429	5,425	5,425	5,425
2050	5,454	5,454	5,454	5,454	5,454	5,454	5,450	5,450	5,450

Annual Projected SO_2 Emissions from Generic Resources

Year	1-Baseline (Tons)	A2 (Tons)	A3 (Tons)	A4 (Tons)	A5 (Tons)	B2 (Tons)	B3 (Tons)	B4 (Tons)	B5 (Tons)
2011	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	1	1	1	1	1	1	0	0	0
2019	2	2	2	2	2	1	1	1	1
2020	4	4	4	4	3	3	2	2	2
2021	7	6	6	6	5	4	4	3	3
2022	12	10	10	9	9	7	6	5	5
2023	75	72	72	72	71	63	60	61	58
2024	73	70	69	69	68	59	57	57	55
2025	71	67	66	66	66	56	55	55	53
2026	74	70	70	70	69	60	58	58	56
2027	121	115	115	115	113	97	95	95	91
2028	117	110	110	110	108	92	90	90	87
2029	122	116	116	116	114	98	96	96	92
2030	127	120	120	120	118	101	99	99	95
2031	133	126	125	125	124	107	105	104	101
2032	138	131	130	130	129	112	109	109	105
2033	185	177	176	176	174	154	151	151	146
2034	211	203	203	203	201	180	178	178	174
2035	209	201	200	200	198	178	176	176	172
2036	271	262	261	261	259	235	231	231	226
2037	279	270	270	270	268	243	243	242	238
2038	297	288	288	288	286	260	261	260	255
2039	304	295	295	295	293	266	266	266	261
2040	296	286	286	286	284	259	259	259	253
2041	310	310	310	310	308	292	292	292	287
2042	1,284	1,284	1,284	1,284	1,281	1,270	1,271	1,271	1,264
2043	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292
2044	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294	1,294
2045	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
2046	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296
2047	1,304	1,304	1,304	1,304	1,304	1,304	1,305	1,305	1,305
2048	1,338	1,338	1,338	1,338	1,338	1,338	1,338	1,338	1,338
2049	1,326	1,326	1,326	1,326	1,326	1,326	1,326	1,326	1,326
2050	1,345	1,345	1,345	1,345	1,345	1,345	1,346	1,346	1,346

Annual Projected NO_x Emissions from Generic Resources

Year	1-Baseline (Tons)	A2 (Tons)	A3 (Tons)	A4 (Tons)	A5 (Tons)	B2 (Tons)	B3 (Tons)	B4 (Tons)	B5 (Tons)
2011	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	7	6	6	6	5	5	2	2	2
2019	10	9	9	9	9	8	5	4	4
2020	23	21	20	19	19	16	12	10	10
2021	37	33	32	31	30	24	19	15	16
2022	65	56	54	52	50	40	33	29	28
2023	316	301	299	299	295	261	250	252	240
2024	308	291	289	289	285	247	239	237	228
2025	295	278	277	276	273	235	227	226	218
2026	310	294	292	292	287	248	240	240	232
2027	499	475	472	472	466	400	389	387	374
2028	479	453	451	451	445	380	370	368	356
2029	503	478	476	476	470	404	393	392	378
2030	525	497	494	494	488	419	409	406	392
2031	550	521	518	518	512	441	431	428	414
2032	575	543	540	540	533	462	452	449	434
2033	759	727	724	724	716	631	619	618	599
2034	872	838	835	835	827	742	731	729	712
2035	862	827	824	824	817	734	724	722	705
2036	1,114	1,076	1,072	1,072	1,064	962	949	948	926
2037	1,147	1,108	1,108	1,108	1,099	996	996	994	974
2038	1,222	1,183	1,183	1,183	1,174	1,070	1,070	1,068	1,048
2039	1,252	1,213	1,213	1,213	1,204	1,095	1,095	1,095	1,072
2040	1,218	1,179	1,179	1,179	1,170	1,063	1,064	1,064	1,040
2041	1,280	1,280	1,280	1,280	1,271	1,204	1,205	1,205	1,180
2042	2,007	2,007	2,007	2,007	1,996	1,963	1,964	1,964	1,935
2043	2,031	2,031	2,031	2,031	2,031	2,031	2,032	2,032	2,032
2044	2,042	2,042	2,042	2,042	2,042	2,042	2,042	2,042	2,042
2045	2,108	2,108	2,108	2,108	2,108	2,108	2,110	2,110	2,110
2046	2,090	2,090	2,090	2,090	2,090	2,090	2,092	2,092	2,092
2047	2,113	2,113	2,113	2,113	2,113	2,113	2,115	2,115	2,115
2048	2,219	2,219	2,219	2,219	2,219	2,219	2,220	2,220	2,220
2049	2,186	2,186	2,186	2,186	2,186	2,186	2,187	2,187	2,187
2050	2,238	2,238	2,238	2,238	2,238	2,238	2,238	2,238	2,238

Annual Projected PM Emissions from Generic Resources

Year	1-Baseline (Tons)	A2 (Tons)	A3 (Tons)	A4 (Tons)	A5 (Tons)	B2 (Tons)	B3 (Tons)	B4 (Tons)	B5 (Tons)
2011	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	1	1	1	1	1	1	0	0	0
2019	1	1	1	1	1	1	1	1	1
2020	3	3	3	3	3	2	2	1	2
2021	5	5	5	5	4	4	3	2	2
2022	10	8	8	8	7	6	5	4	4
2023	72	68	68	68	67	59	57	58	55
2024	70	66	66	66	65	56	55	55	53
2025	67	63	63	63	62	54	52	52	50
2026	70	67	66	66	66	57	55	55	53
2027	116	110	110	110	108	93	91	90	87
2028	111	105	105	105	103	88	86	86	83
2029	117	111	111	111	109	94	92	92	88
2030	121	115	114	114	113	97	95	94	91
2031	126	120	119	119	118	102	100	99	96
2032	131	124	124	124	122	106	104	104	100
2033	176	169	168	168	167	147	144	144	140
2034	202	194	194	194	192	172	170	170	166
2035	199	192	191	191	190	170	168	168	164
2036	259	250	250	250	248	224	221	221	217
2037	267	258	258	258	256	232	232	232	227
2038	284	275	275	275	273	249	249	249	244
2039	290	281	281	281	280	254	255	255	250
2040	282	274	274	274	272	247	247	247	242
2041	296	296	296	296	294	279	279	279	274
2042	619	619	619	619	616	608	608	608	602
2043	624	624	624	624	624	624	624	624	624
2044	626	626	626	626	626	626	626	626	626
2045	637	637	637	637	637	637	637	637	637
2046	633	633	633	633	633	633	633	633	633
2047	639	639	639	639	639	639	639	639	639
2048	669	669	669	669	669	669	669	669	669
2049	660	660	660	660	660	660	660	660	660
2050	674	674	674	674	674	674	674	674	674

Annual Projected Mercury Emissions from Generic Resources

Year	1-Baseline (lbs)	A2 (lbs)	A3 (lbs)	A4 (lbs)	A5 (lbs)	B2 (lbs)	B3 (lbs)	B4 (lbs)	B5 (lbs)
2011	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-
2033	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-
2042	30	30	30	30	30	30	30	30	30
2043	30	30	30	30	30	30	30	30	30
2044	30	30	30	30	30	30	30	30	30
2045	30	30	30	30	30	30	30	30	30
2046	30	30	30	30	30	30	30	30	30
2047	30	30	30	30	30	30	30	30	30
2048	30	30	30	30	30	30	30	30	30
2049	30	30	30	30	30	30	30	30	30
2050	30	30	30	30	30	30	30	30	30

Annual Projected CO_2 Emissions from Generic Resources

Year	1-Baseline ('000 Tons)	A2 ('000	A3 ('000	A4 ('000	A5 ('000	B2 ('000	B3 ('000	B4 ('000	B5 ('000
2011	-	-	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-	-	-
2014	-	-	-	-	-	-	-	-	-
2015	-	-	-	-	-	-	-	-	-
2016	-	-	-	-	-	-	-	-	-
2017	-	-	-	-	-	-	-	-	-
2018	25	22	22	21	20	19	9	8	8
2019	38	35	34	33	32	29	19	16	16
2020	87	78	77	73	71	60	47	37	40
2021	138	124	121	117	111	90	73	60	62
2022	243	208	202	195	187	149	129	112	109
2023	1,919	1,832	1,824	1,824	1,800	1,594	1,540	1,557	1,485
2024	1,866	1,772	1,760	1,760	1,739	1,505	1,467	1,463	1,409
2025	1,802	1,701	1,692	1,692	1,671	1,441	1,403	1,401	1,350
2026	1,885	1,788	1,781	1,782	1,757	1,518	1,478	1,487	1,434
2027	3,111	2,962	2,947	2,948	2,910	2,495	2,436	2,430	2,349
2028	2,992	2,830	2,816	2,816	2,780	2,373	2,313	2,307	2,228
2029	3,138	2,985	2,973	2,973	2,938	2,524	2,459	2,460	2,369
2030	3,249	3,079	3,065	3,065	3,028	2,601	2,547	2,537	2,448
2031	3,391	3,216	3,201	3,204	3,168	2,734	2,679	2,667	2,580
2032	3,517	3,337	3,323	3,322	3,285	2,850	2,793	2,785	2,695
2033	4,739	4,540	4,522	4,522	4,476	3,947	3,879	3,873	3,761
2034	5,417	5,213	5,198	5,198	5,153	4,628	4,567	4,560	4,460
2035	5,356	5,148	5,132	5,132	5,090	4,576	4,516	4,510	4,408
2036	6,967	6,730	6,711	6,711	6,662	6,028	5,951	5,947	5,820
2037	7,175	6,935	6,935	6,935	6,885	6,238	6,240	6,233	6,113
2038	7,625	7,384	7,384	7,384	7,336	6,686	6,689	6,683	6,564
2039	7,796	7,560	7,560	7,560	7,512	6,833	6,837	6,837	6,709
2040	7,583	7,349	7,349	7,349	7,301	6,637	6,639	6,639	6,510
2041	7,946	7,946	7,946	7,946	7,901	7,488	7,492	7,492	7,360
2042	9,421	9,421	9,421	9,421	9,363	9,163	9,167	9,167	9,012
2043	9,531	9,531	9,531	9,531	9,531	9,531	9,536	9,536	9,536
2044	9,607	9,607	9,607	9,607	9,607	9,607	9,611	9,611	9,611
2045	9,961	9,961	9,961	9,961	9,961	9,961	9,968	9,968	9,968
2046	9,849	9,849	9,849	9,849	9,849	9,849	9,856	9,856	9,856
2047	9,972	9,972	9,972	9,972	9,972	9,972	9,981	9,981	9,981
2048	10,760	10,760	10,760	10,760	10,760	10,760	10,766	10,766	10,766
2049	10,555	10,555	10,555	10,555	10,555	10,555	10,560	10,560	10,560
2050	10,879	10,879	10,879	10,879	10,879	10,879	10,883	10,883	10,883

Attachment 2.8-3 Sensitivity Results

This section contains the generic expansion plans of the low and high sales forecast sensitivities as well as graphs showing annual net cost deltas of the alternative plans versus the baseline case under the various sensitivity analyses.

Expansion Plan of the Low Sales Forecast Sensitivity

Year	Baseload[1]	2x1[1] Combined Cycle	1x1[1] Combined Cycle	Combustion Turbine[1]	Battery	Wind[2]	Solar PV[2]	Solar Thermal
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019						100 MW		
2020				173 MW				
2021								
2022				346 MW				
2023		643 MW						
2024								
2025						200 MW		
2026								
2027				173 MW				
2028						600 MW		
2029				346 MW				
2030				173 MW				
2031				173 MW			100 MW	
2032						300 MW		
2033		643 MW				200 MW		
2034								
2035						200 MW		
2036		643 MW						
2037						200 MW		
2038						400 MW		
2039								
2040						100 MW		
2041				173 MW				
2042	485 MW	643 MW						
2043						100 MW		
2044								
2045								
2046				173 MW				
2047								
2048								
2049				173 MW				
2050								

(1) Listed as summer accredited capacity rating

(2) Listed as nameplate capacity. Renewable energy additions shown include additions to replace expiring contracts.

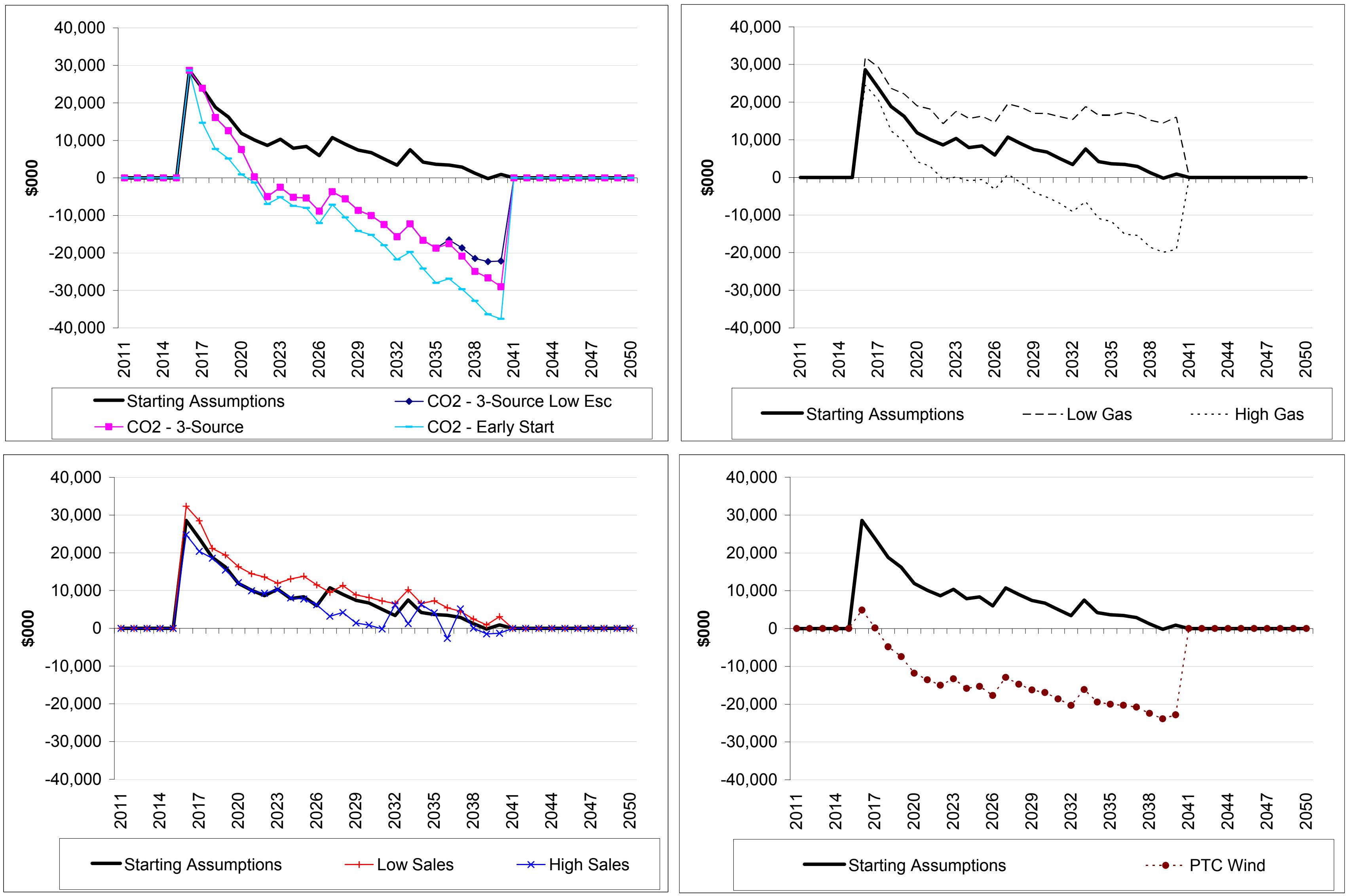
Expansion Plan of the High Sales Forecast Sensitivity

Year	Baseload[1]	2x1[1] Combined Cycle	1x1[1] Combined Cycle	Combustion Turbine[1]	Battery	Wind[2]	Solar PV[2]	Solar Thermal
2011								
2012								
2013								
2014								
2015				346 MW				
2016								
2017				346 MW				
2018		658 MW						
2019						100 MW		
2020								
2021				173 MW				
2022				346 MW				
2023		643 MW						
2024								
2025						200 MW		
2026								
2027				346 MW				
2028				173 MW		600 MW		
2029				346 MW				
2030				173 MW				
2031				173 MW			100 MW	
2032		643 MW				300 MW		
2033						200 MW		
2034		643 MW						
2035						200 MW		
2036								
2037		643 MW				200 MW		
2038						400 MW		
2039								
2040						100 MW		
2041								
2042	485 MW	643 MW						
2043		643 MW				100 MW		
2044								
2045								
2046								
2047								
2048								
2049								
2050				173 MW				

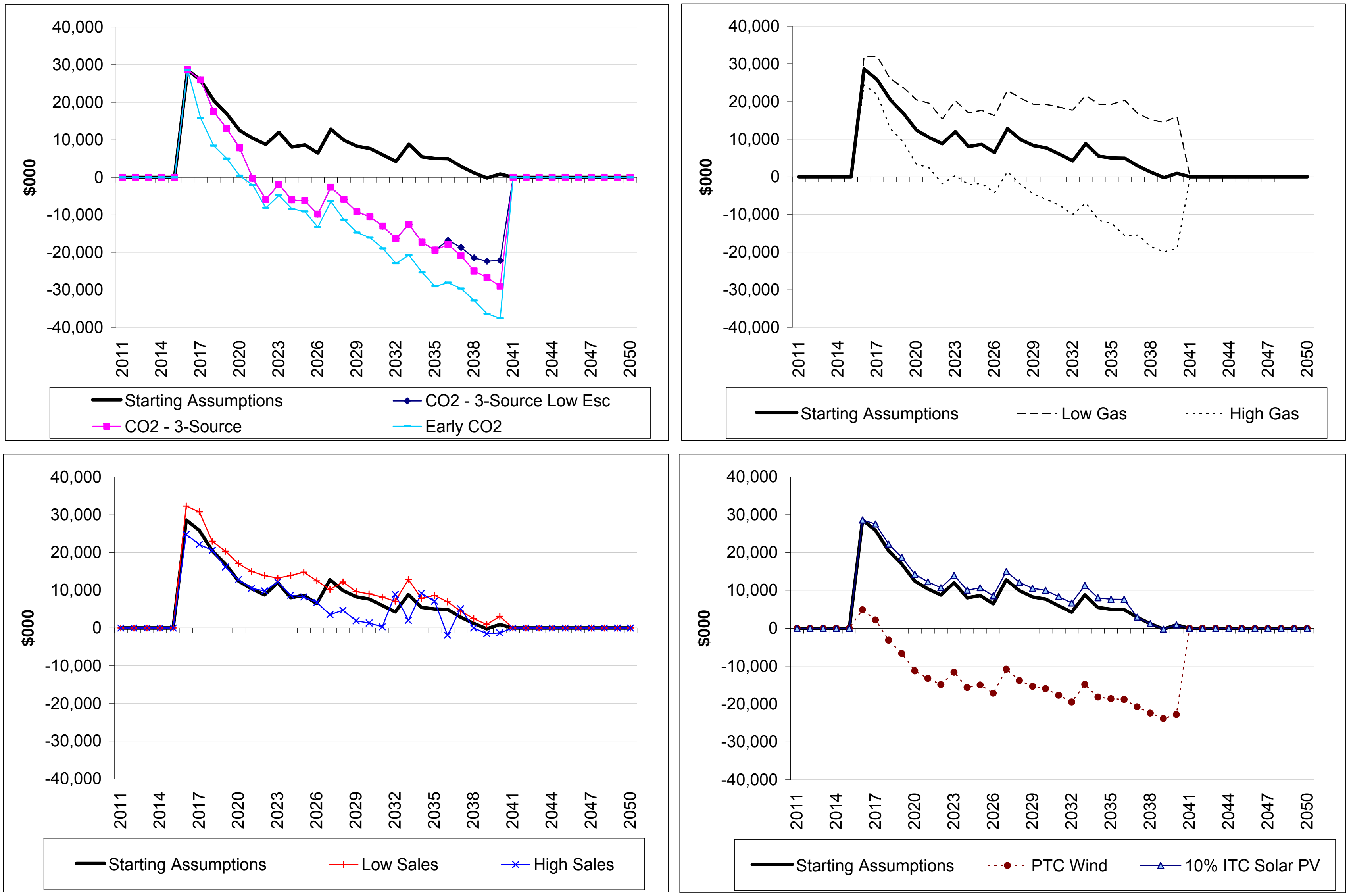
(1) Listed as summer accredited capacity rating

(2) Listed as nameplate capacity. Renewable energy additions shown include additions to replace expiring contracts.

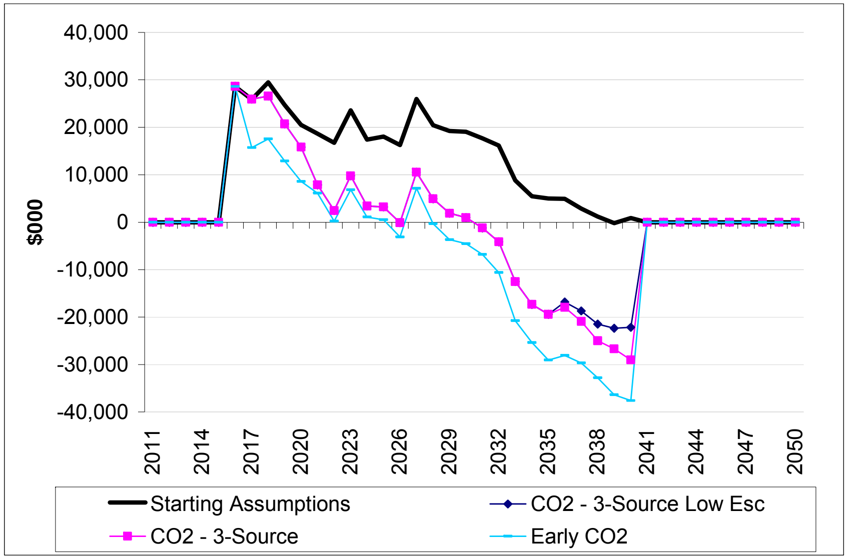
Sensitivity Results of Alternative Plan A2 vs. Least-Cost Baseline Case

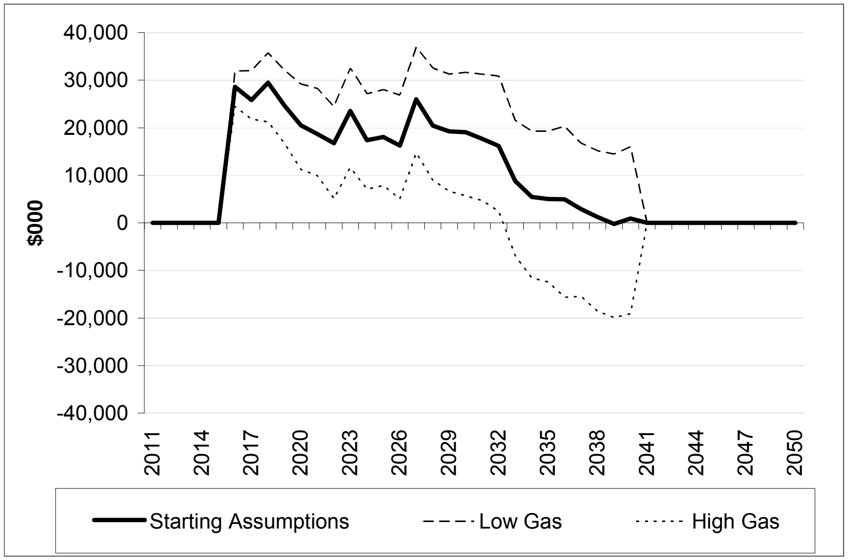


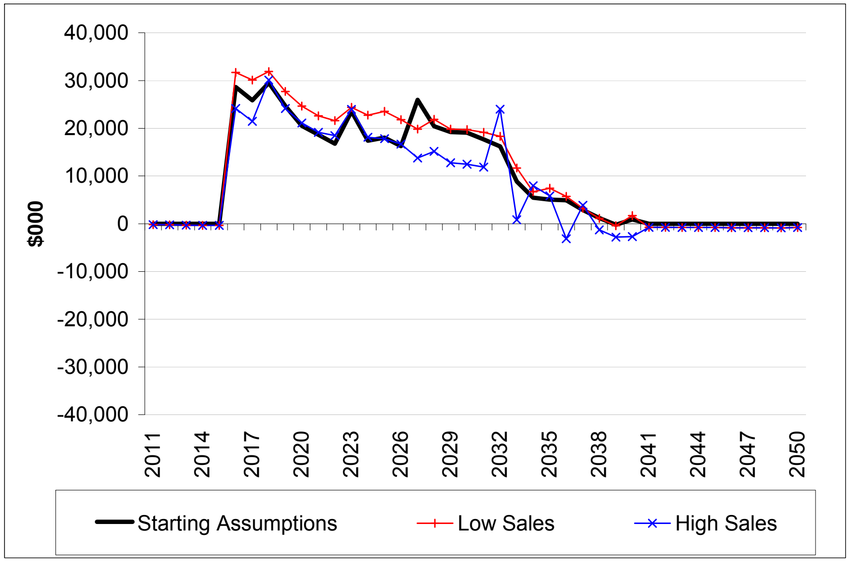
Sensitivity Results of Alternative Plan A3 vs. Least-Cost Baseline Case

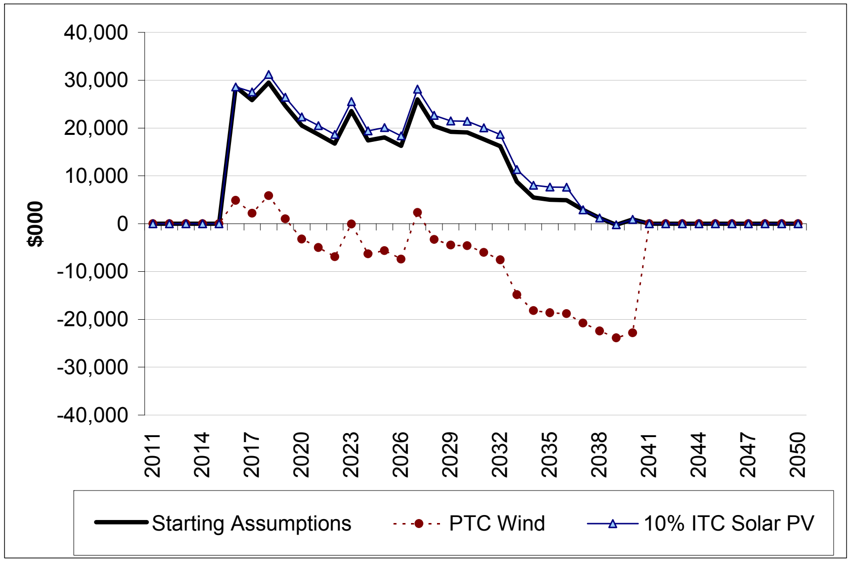


Sensitivity Results of Alternative Plan A4 vs. Least-Cost Baseline Case

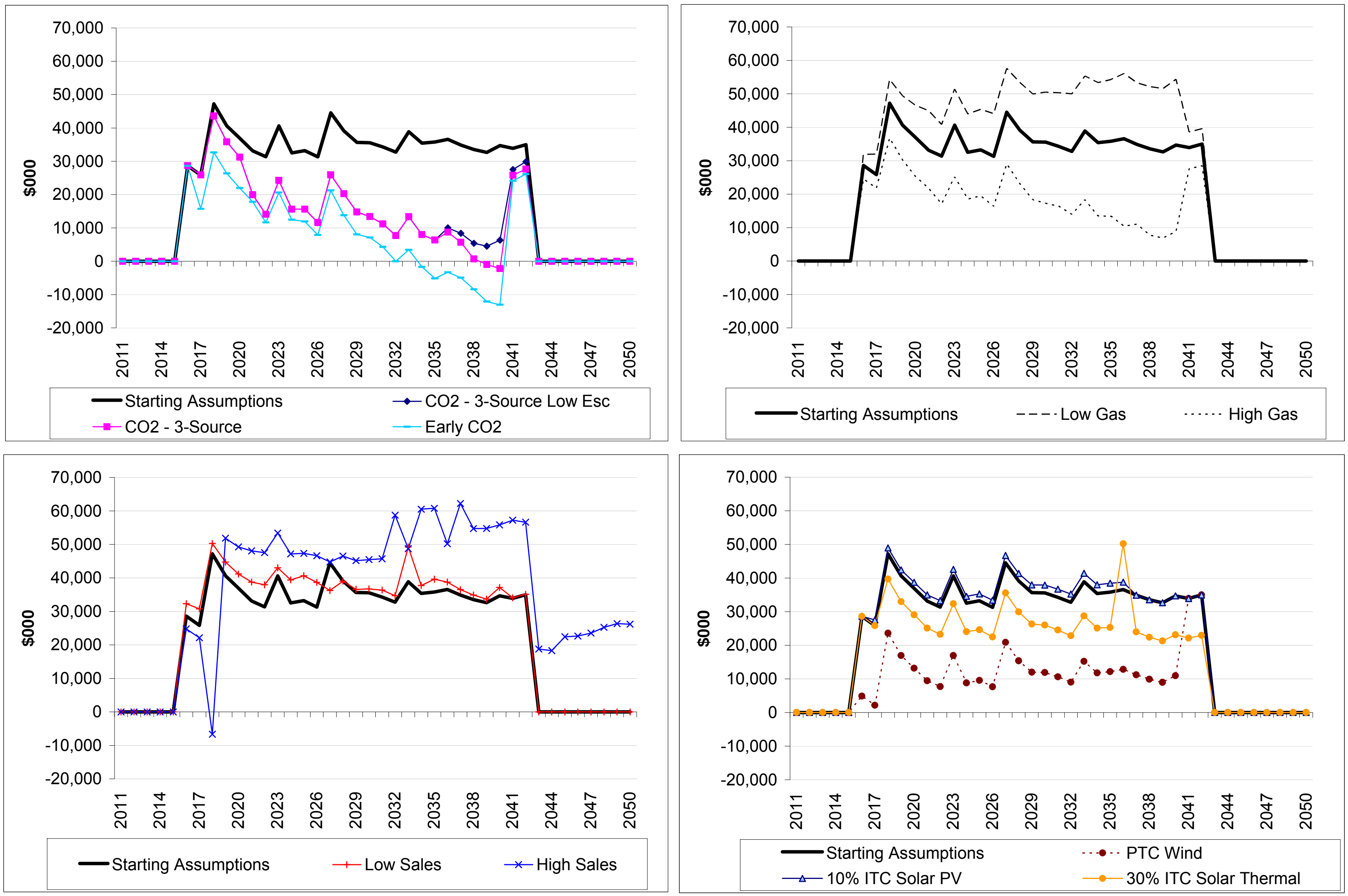




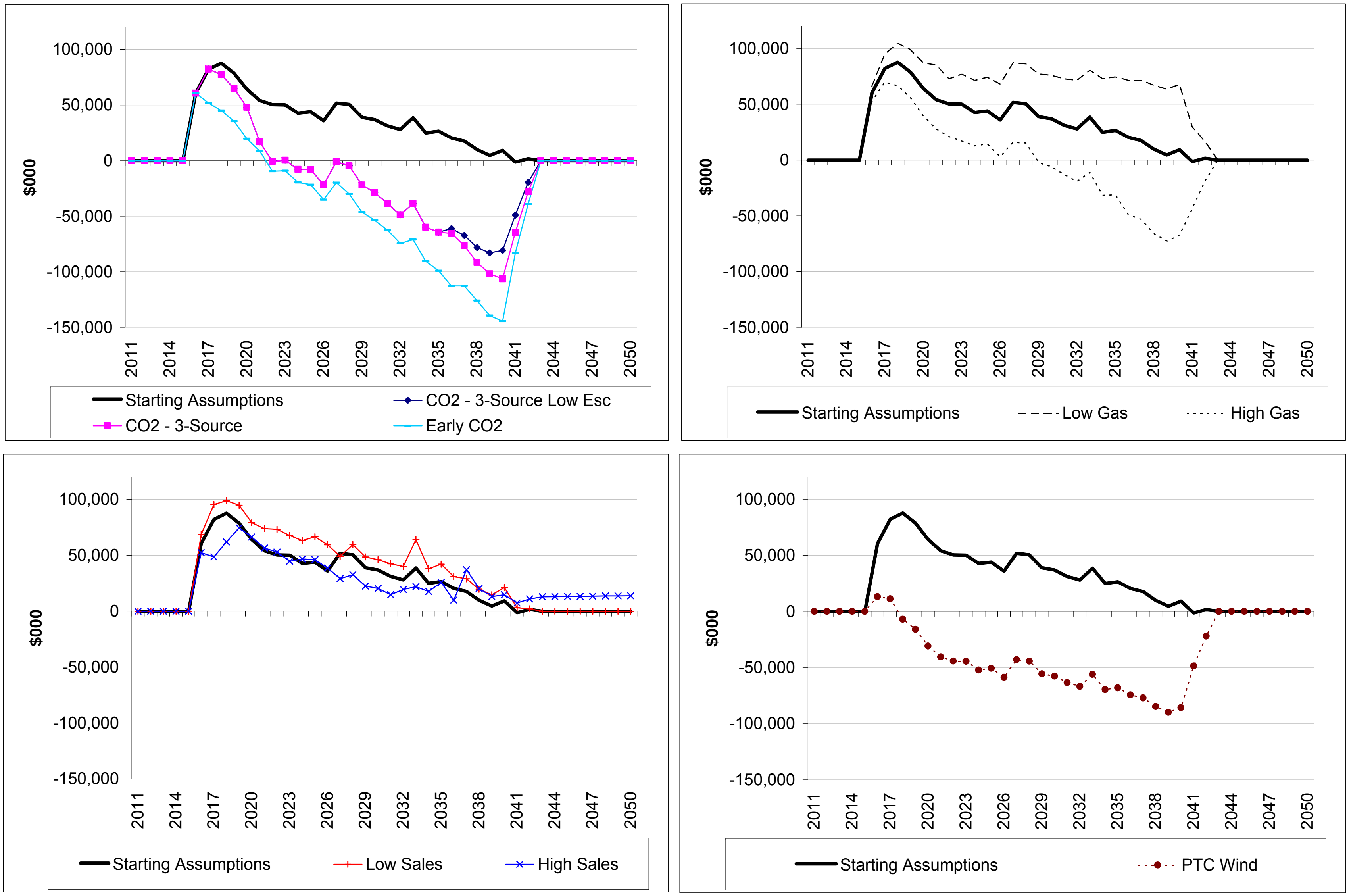


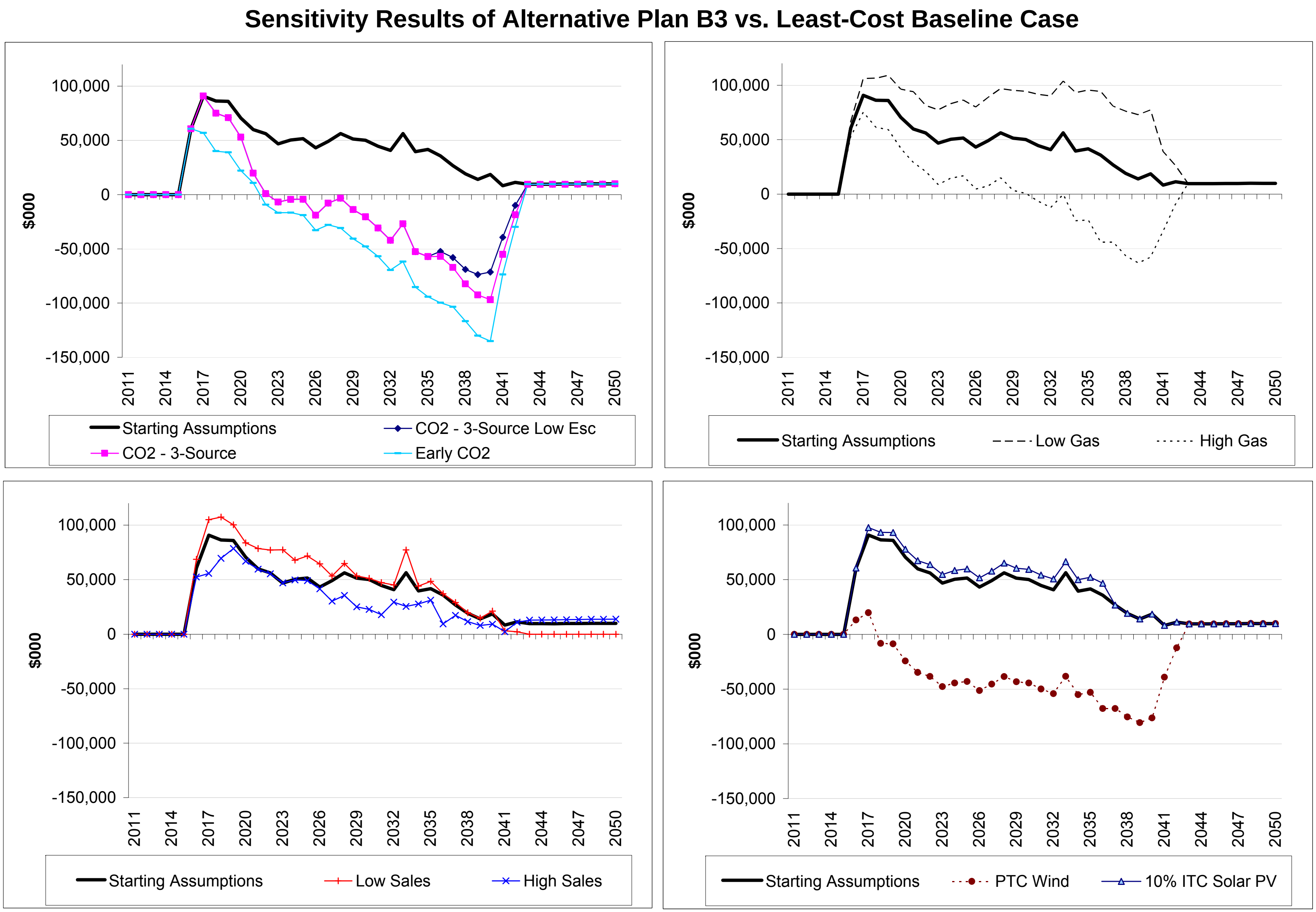


Sensitivity Results of Alternative Plan A5 vs. Least-Cost Baseline Case

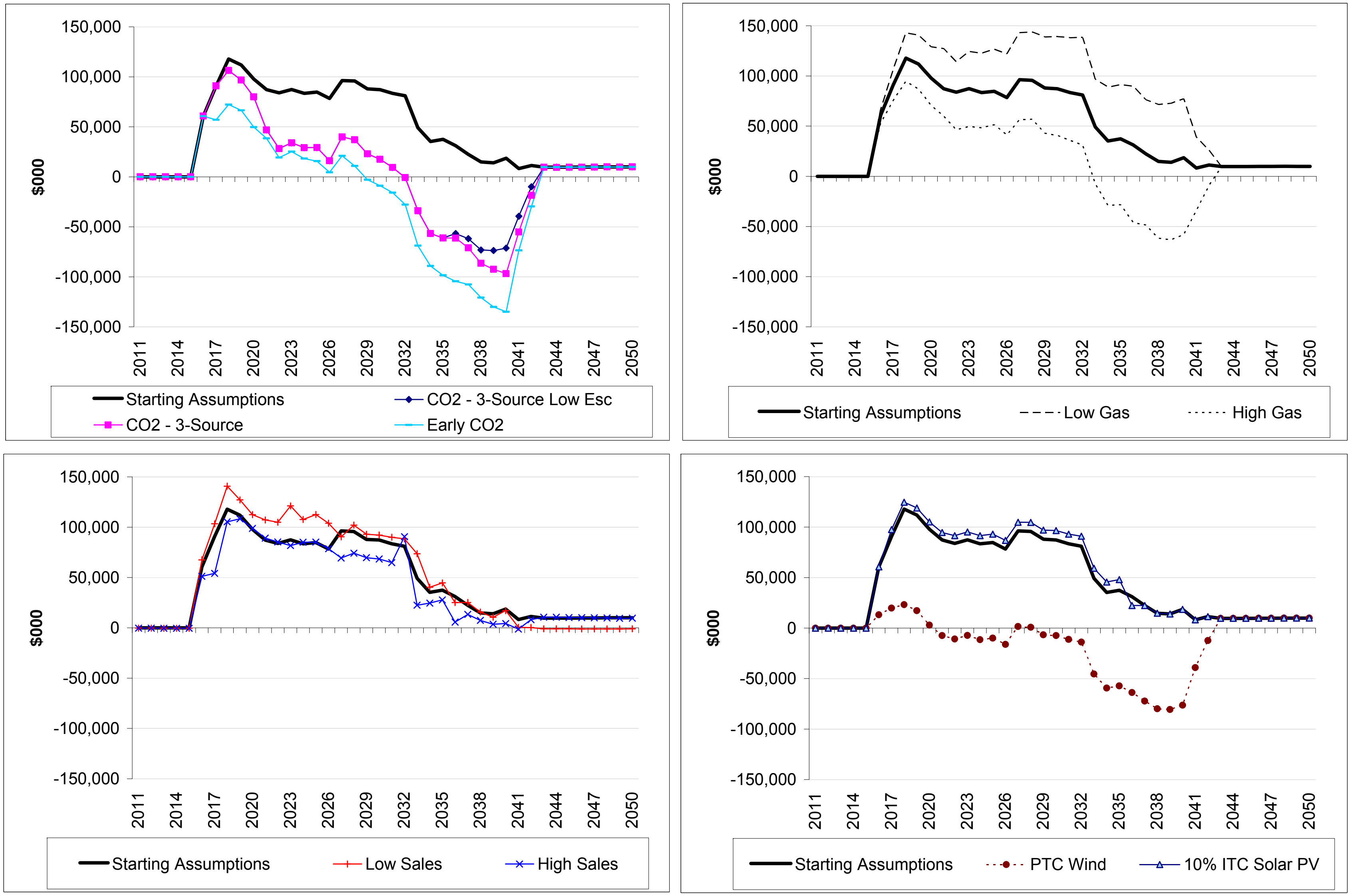


Sensitivity Results of Alternative Plan B2 vs. Least-Cost Baseline Case

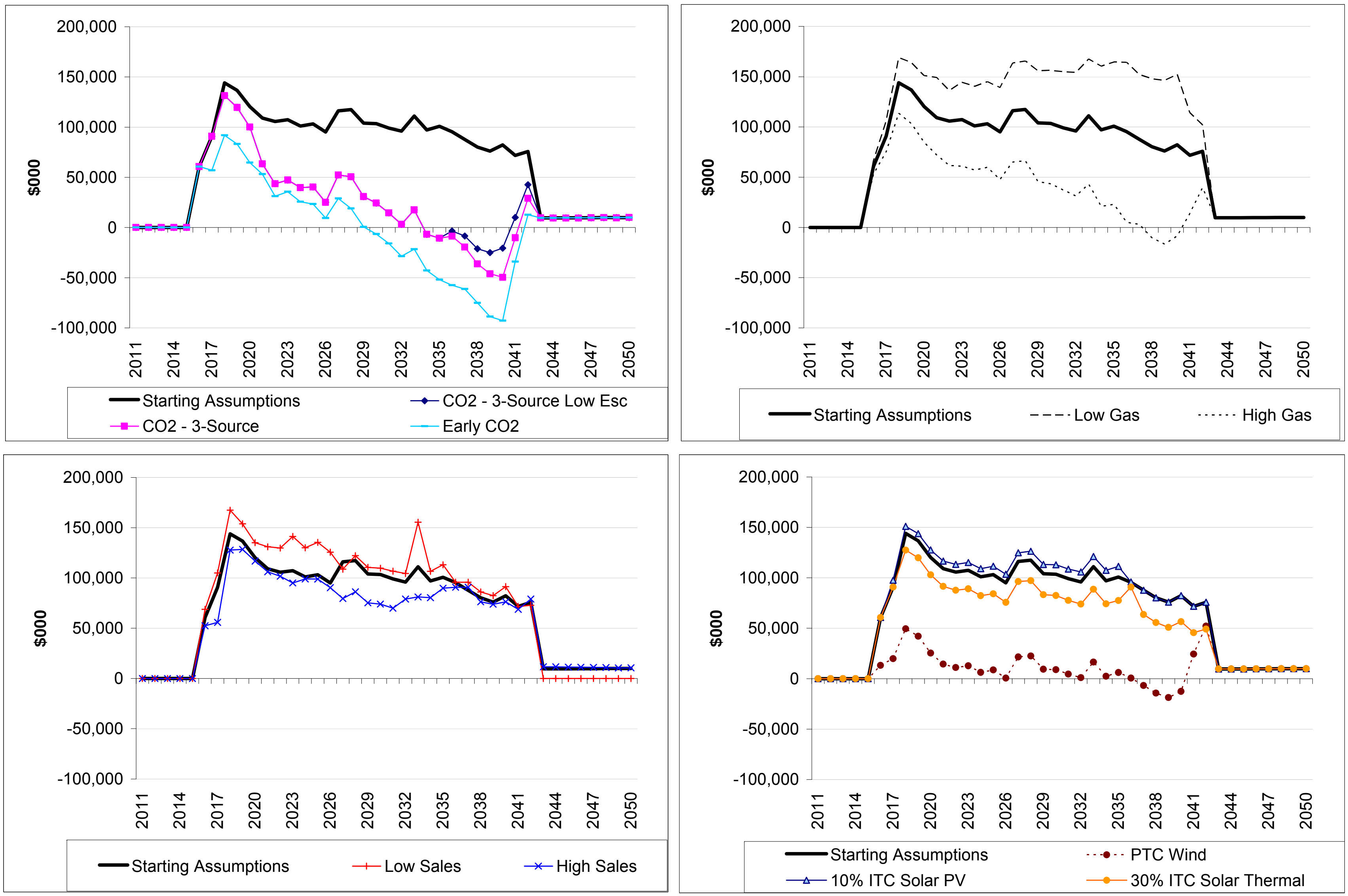



Sensitivity Results of Alternative Plan B3 vs. Least-Cost Baseline Case
$000
100,000
50,000
0
-50,000
-100,000
-150,000
2011
2014
2017
2020
2023
2026
2029
2032
2035
2038
2041
2044
2047
2050
Starting Assumptions
CO2 - 3-Source Low Esc
CO2 - 3-Source
Early CO2
Low Gas
High Gas
Low Sales
High Sales
PTC Wind
10% ITC Solar PV

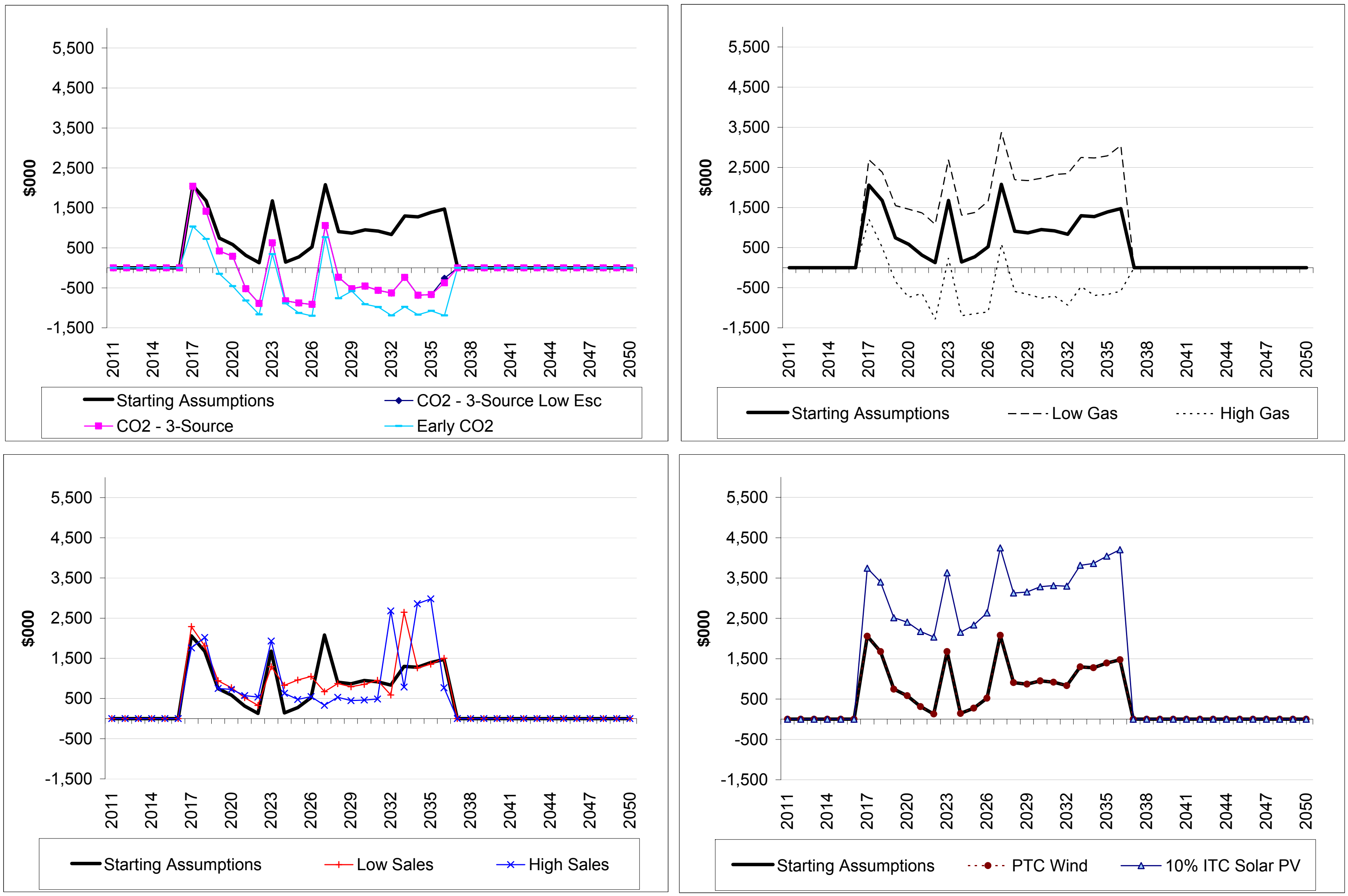
Sensitivity Results of Alternative Plan B4 vs. Least-Cost Baseline Case



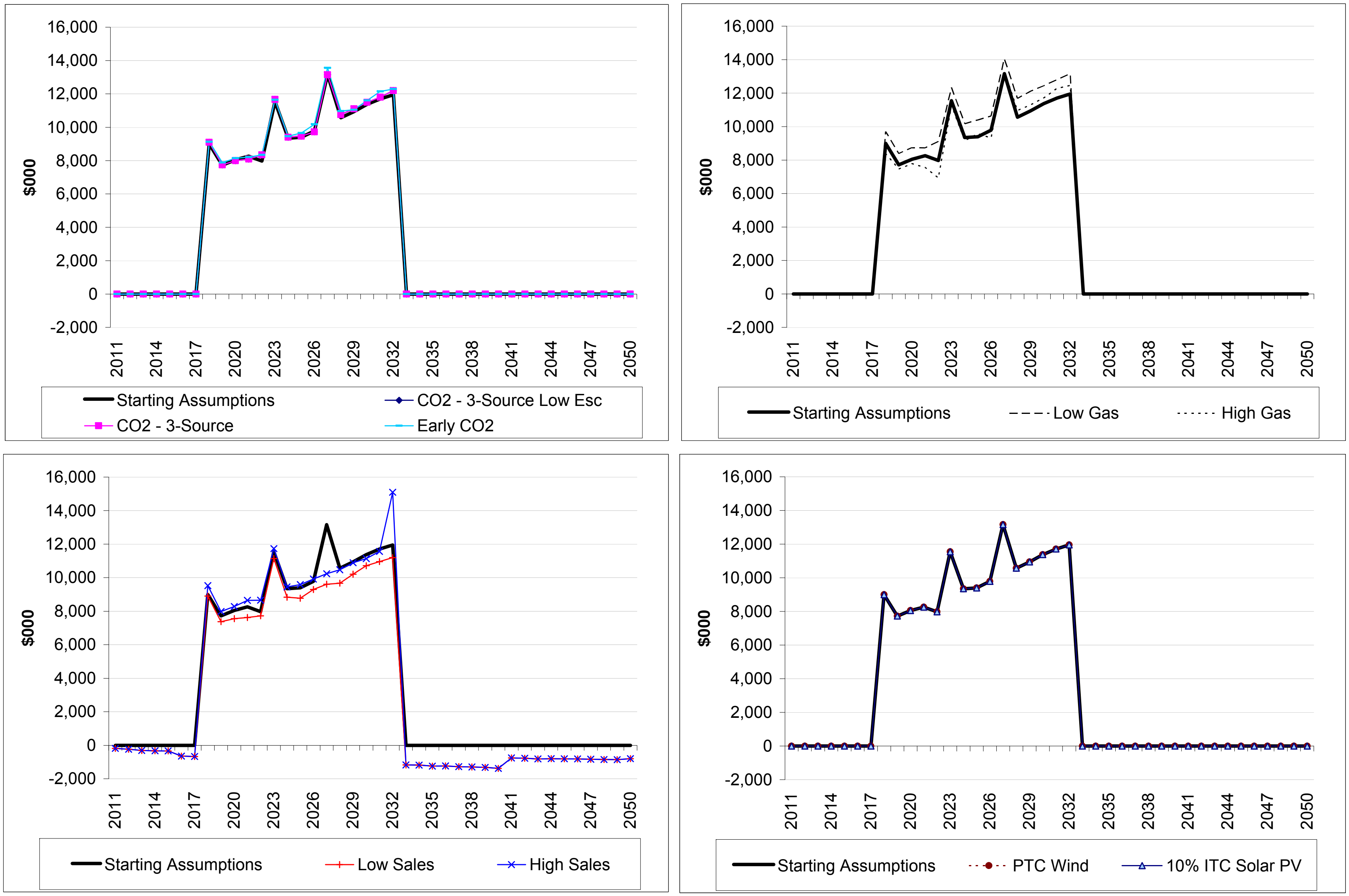
Sensitivity Results of Alternative Plan B5 vs. Least-Cost Baseline Case



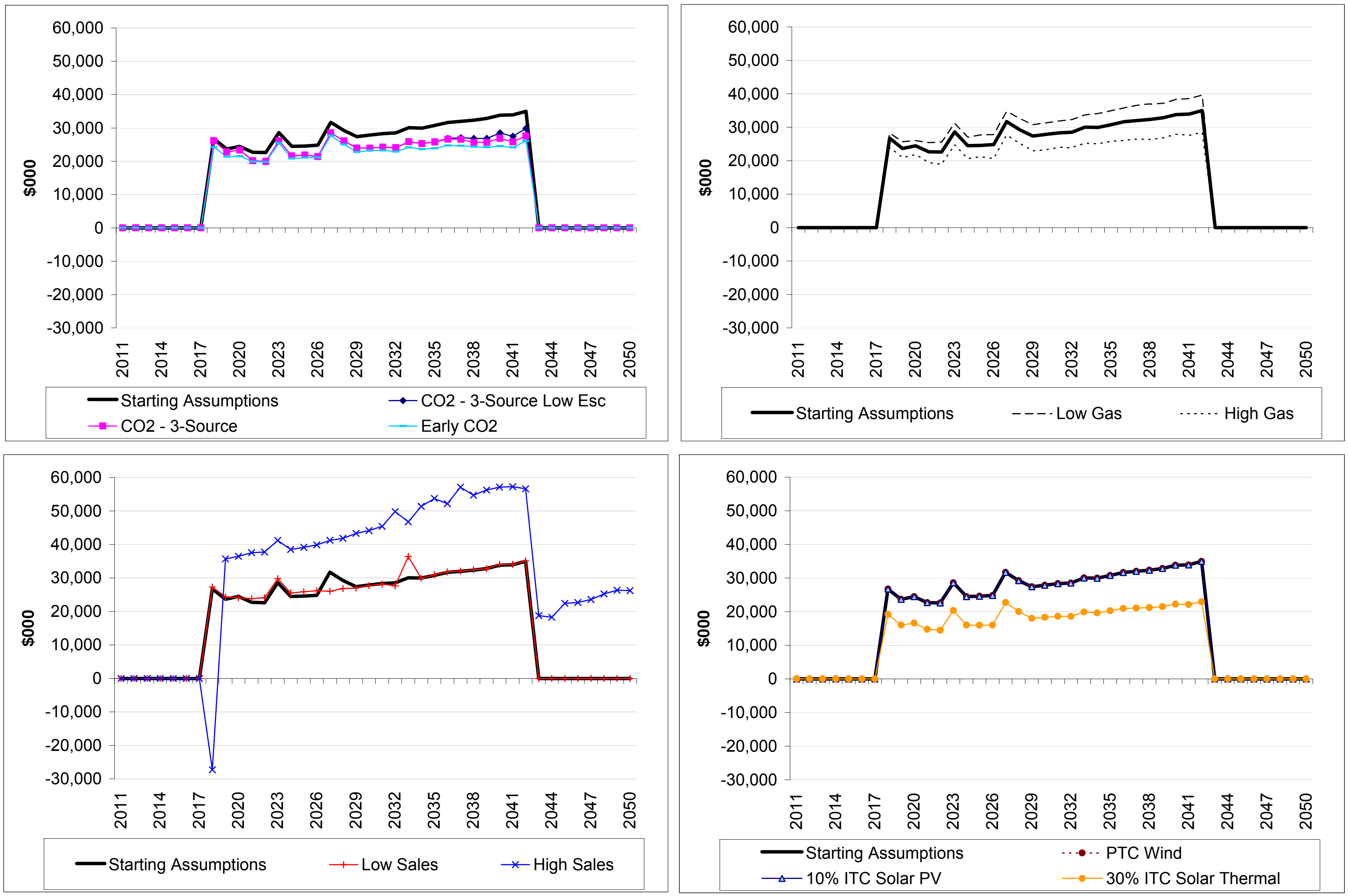
Sensitivity Results of Alternative Plan A3 versus A2 (Isolates 25 MW solar PV)



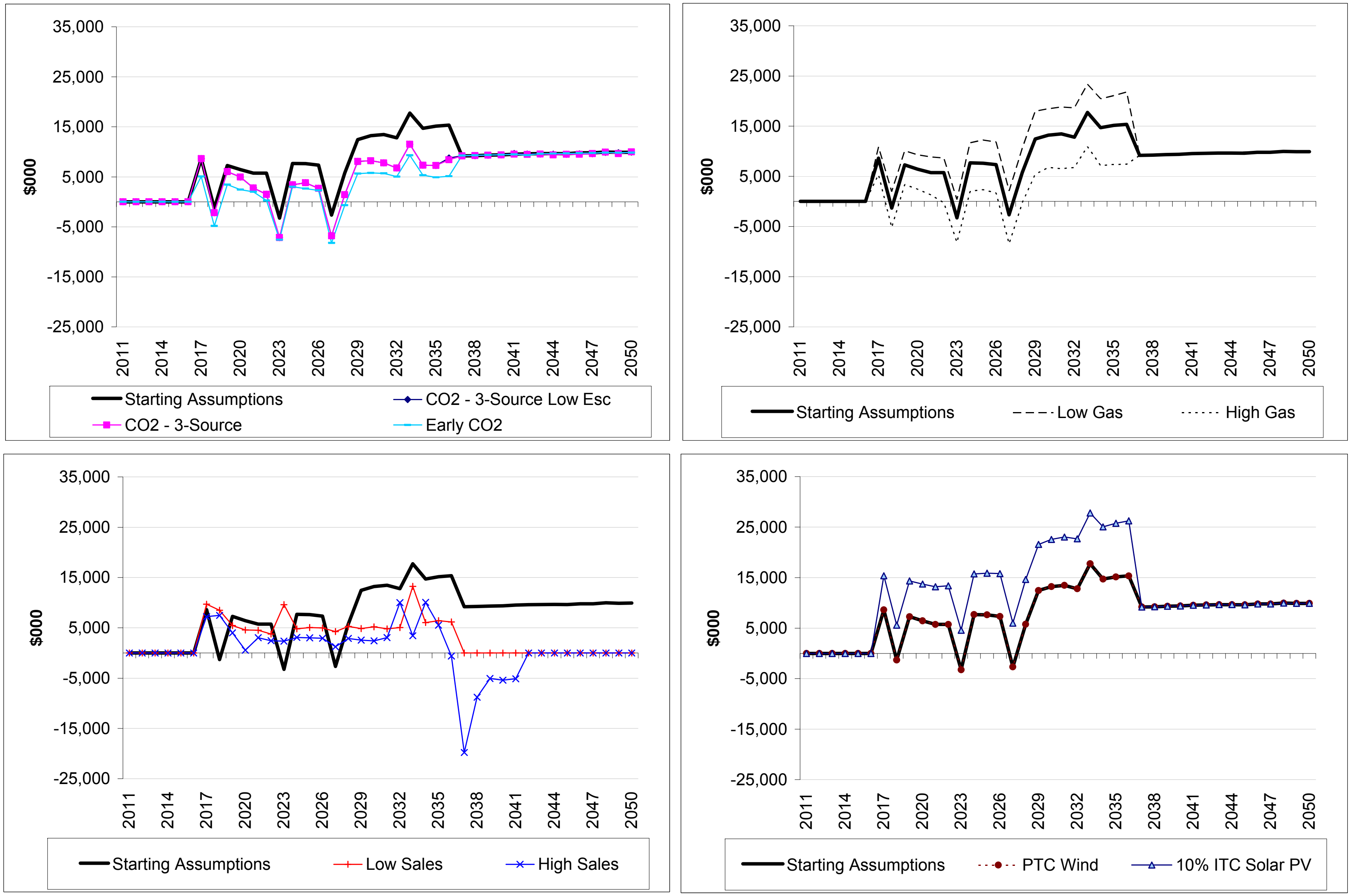
Sensitivity Results of Alternative Plan A4 versus A3 (Isolates 25 MW Battery)



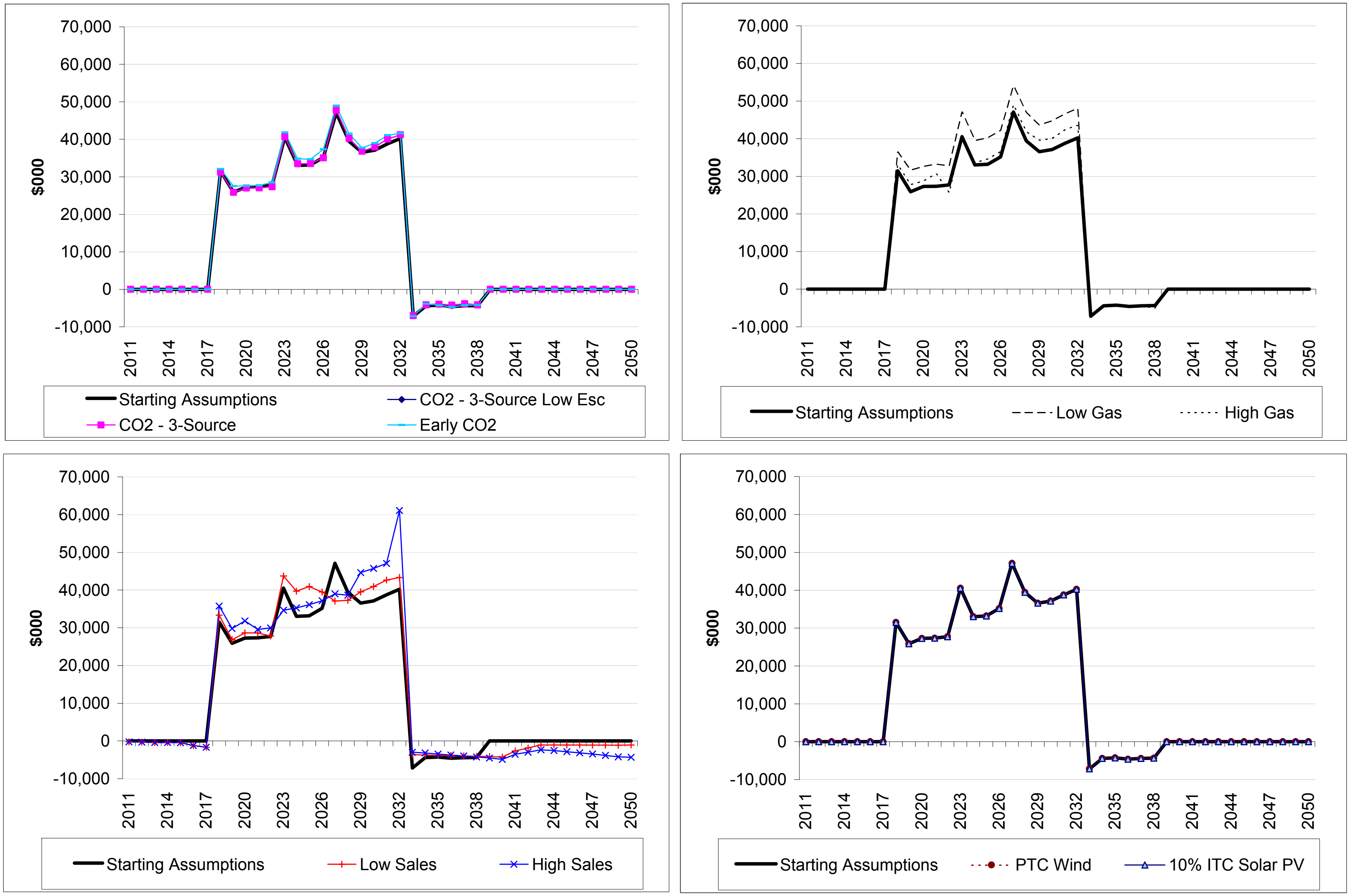
Sensitivity Results of Alternative Plan A5 versus A3 (Isolates 50 MW Solar Thermal)



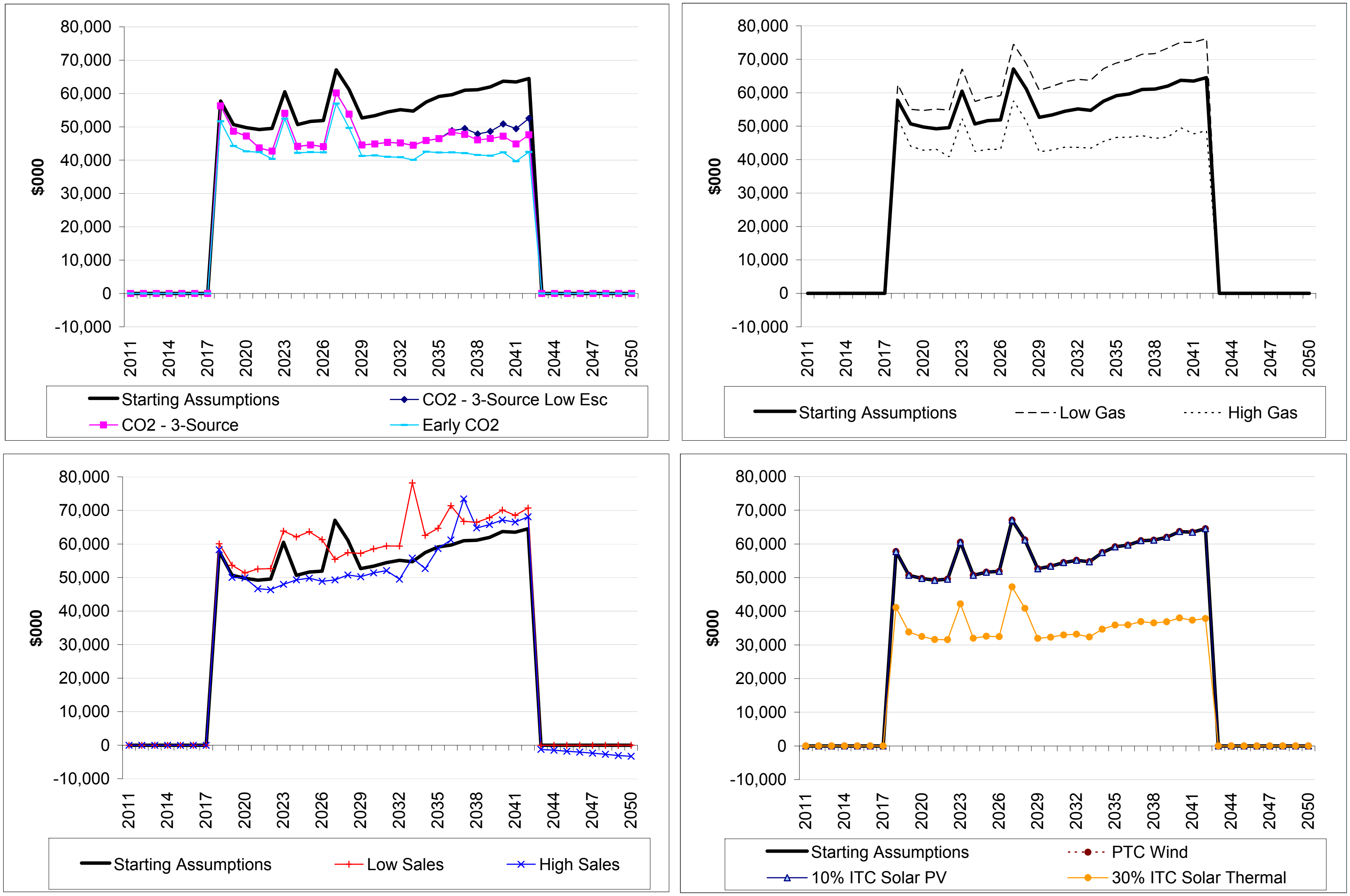
Sensitivity Results of Alternative Plan B3 versus B2 (Isolates 100 MW Solar PV)



Sensitivity Results of Alternative Plan B4 versus B3 (Isolates 100 MW Battery)



Sensitivity Results of Alternative Plan B5 versus B3 (Isolates 125 MW Solar Thermal)



Attachment 2.8-4 LEC Calculations in Figure 1.5-1 of Volume 1

Figure 1.5-1 shows Levelized Energy Cost ("LEC") values for the various resources considered in the RAP. For LEC values to be helpful in understanding how different technologies can contribute towards providing both capacity and energy to the system, Pubic Service developed LEC values such that each technology was put on an equivalent basis with regard to 1) the amount of energy included in the LCE calculation; and 2) the amount of firm generation capacity included in the LCE calculation.

The amount of annual energy production used in the LEC calculation was the amount equal to that produced at a 45% annual capacity factor.[31] Aside from the wind , gas CC, and baseload coal technologies, the other generation resources shown in Tables 2.8-1 and 2.8-2 would operate below this 45% capacity factor level and therefore additional system energy was included in the LEC calculation for those generation resources such that a 45% capacity factor was represented. For example, a 10 MW solar PV facility is expected to generate at approximately 25% capacity factor annually or 21,900 MWh (10 MW x 8760 hours x 0.25) which is 20% less than the 45% capacity factor level of wind and or CCs. Therefore, in developing the LEC for this solar PV facility an additional 17,520 MWh of energy is included in the derivation to put it on a comparable capacity factor basis as wind and CC. The source of this additional 17,520 MWh of energy would be Public Service electric system energy, and for purposes of these LEC calculations, it was assumed that a 7,000 btu/kWh heat rate times the forecast price of natural gas was a reasonable estimate for the cost of system energy.[32] The same capacity factor adjustment approach was included when developing LEC estimates for the solar thermal generation resource which is assumed to operate at a 35% CF (thus 10% system energy is included in the LEC) and gas CT's which are assumed to operate at a 5% CF (thus 40% system energy is include in the LEC).

Regarding the amount of firm capacity included in each LEC, the $/kW fixed cost of a gas CT was used to "firm up" wind and solar PV generation resources. Gas CT, gas CC, and solar thermal with storage generation resources provide firm generation capacity to the system at a level equal to 100% of their nameplate rating so no such firming adjustments were applied in their LEC representations. However wind and solar PV provide a level of firm generation to the system that is less than their nameplate ratings. For example, a 10 MW solar PV facility is expected to provide firm generation capacity to the system of approximately 50% of its 10 MW rating or 5 MW. Therefore, in developing the LEC for this solar PV facility an additional 5 MW of firm capacity is included in the derivation so that the

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[31] The annual capacity factor for a facility equals the amount of energy generated by a facility in a year divided by the amount of energy the facility could generate by operating a full output for all hours of the year.

[32] Beyond 2018 it is expected that gas combined cycle facilities will be operating as the marginal unit for much of the time during both on-peak and off-peak periods.

resulting value reflects a capacity contribution to the system equal to 10 MW or 100% of its nameplate rating. For purposes of these LEC calculations the fixed cost of a generic CT, represented in $/kW was used to provide the cost for the additional 5 MW of firm generation capacity. The same firming adjustment approach was included in developing LEC estimates for wind.

Attachment 2.8-4 Table 1 shows the LEC calculations for the RAP resources.

Attachment 2.8-4 Table 1 - LEC calculations for the RAP resources

A	B	C	D	E	F	G	I	J	H=B*D+G*(1-D)	K=C*E+J*(1-E)	L=K+H*12/ 8760*1000
Resource	**Capacity Cost ($/kw-mo)**	**Energy Cost ($/MWh)**	**Capacity Credit (%)**	**Capacity Factor (%)**	**Filler Capacity (Resource)**	**Filler Capacity ($/kw-mo)**	**Filler Energy (Resource)**	**Filler Energy ($/MWh)**	**Weighted Capacity ($/kw-mo)**	**Weighted Energy ($/MWh)**	**All-in Cost ($/MWh)**
Combustion Turbine	$6.44	$82	100%	5%	CT	$6.44	2x1 CC	$50	$6.44	$51	$60
2x1 Combined Cycle	$10.30	$50	100%	45%	CT	$6.44	2x1 CC	$50	$10.30	$50	$64
1x1 Combined Cycle	$12.26	$48	100%	45%	CT	$6.44	2x1 CC	$50	$12.26	$49	$66
Non PTC Wind	$0.00	$76	12.50%	45%	CT	$6.44	2x1 CC	$50	$5.64	$62	$69
30% ITC Solar PV	$0.00	$102	55%	30%	CT	$6.44	2x1 CC	$50	$2.90	$65	$69
Battery[1]	$30.00	-$12	100%	20%	CT	$6.44	2x1 CC	$50	$30.00	$37	$78
125 MW 10% ITC Solar Thermal	$0.00	$223	100%	38%	CT	$6.44	2x1 CC	$50	$0.00	$115	$115
50 MW 10% ITC Solar Thermal	$0.00	$253	100%	38%	CT	$6.44	2x1 CC	$50	$0.00	$127	$127

(1) Energy Cost of battery assumed to be the arbitrage value between a CT and a CC, adjusted for a turnaround efficiency of 75%

Attachment 2.8-5 Economic Carrying Charge[33]

Evaluating Investment Alternatives with Unequal Lives

This paper discusses how to properly evaluate project alternatives with unequal lives. The problem of unequal lived alternatives is a common one in economic analysis. The basic approach requires an understanding of the concept of an "economic carrying charge" which properly assigns the economic cost of capital projects over a defined analysis period when the project lifetimes extend beyond the end of the analysis period and thus are in-service for only part of their economic life.[34]

Two Types of Planning Evaluations that Have Truncation Problems

The problem commonly occurs when evaluating power supply proposals along with self-build options. Some evaluations allow self-build options to compete with the power supply contract proposals. In other evaluations, self-build options are only used to "fill-in" capacity that is needed after a set of contracts are selected during a pre-defined contracting period. In this case, the utility must buy from contracts (and cannot self-build) for its incremental power supply needs for a period of time (e.g., for its needs for from 2004 through 2009).

The time frame type of each analysis must be as long as the longest possible contract. Examples of both types of analysis are illustrated on Exhibit 1. In both examples, the build alternatives extend the capacity needs from the end of each proposal's life through the end of the analysis time frame. Although the contracts have unequal lives, they are complete in their representation in that there is no part of the contract that is not represented. However, the build alternatives have useful lives that continue after the analysis period. *It is the build alternatives that are truncated in the analysis, and this truncation problem is the issue that must be addressed*.

The Economic Carrying Charge

Typical new power plants have useful lives of 25 years or more. What is the cost of using that plant for one year? Or five years?

---

[33] NewEnergy Associates (now Ventyx), 2007.

[34] The economic carrying charge derivation herein was taken from paper by J.L. Seelke, Jr.: "Assessing the Benefits of Load Control," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-101, pp. 3892-3901, October 1982.

This answer to this question has two parts, one that is straightforward and a second that is more complex. Plant costs can be characterized as consisting of two components:

1. Operating costs associated with fuel, maintenance, and staffing, and
2. Capital-related costs consisting of revenue requirements related to the capital investment (depreciation, cost of capital payments, income taxes, property taxes, and insurance).

Since the operating costs of the plant are incurred on an annual basis, operating costs are not affected by analysis truncation.

Capital-related costs, however, are impacted by truncation. While one can easily compute the capital-related revenue requirements for each year, the "economic" cost of using a facility for a period of time (say five years) is not the same as the present value of the year-by-year revenue requirements for those five years. Exhibit 2 shows the year-by- year revenue requirements for a power plant with a thirty-year life. As the table shows, the revenue requirements decrease each year as the net plant decreases due to depreciation and the corresponding cost-of-capital charges (which are incurred on net plant) decline as well. The present value of revenue requirements associated with the $100.00 investment shown on Exhibit 2 is $138.28, or $1.3828 per $1.00 of investment.

The economic carrying charge is the preferred and proper method to evaluate the economic value of using a facility for <u>part</u> of its life. The analysis framework of the economic carrying charge is developed as follows:

1. Assume that a company is planning to construct a power plant for its own load. To give this illustration some texture, suppose that it is a combined cycle plant.
2. Assume further that a power project developer offers to construct the identical facility for the company, operate it, and sell it power from the plant for five years, after which the company will construct the combined cycle it had originally planned, albeit delayed by five years.
3. The power producer quotes operating costs for the power sale that are identical to the operating costs of the company's combined cycle build option. Therefore, buying from the power producer will not cause the company to pay an operating cost premium.
4. The purchase will enable the company to defer the construction of its own (identical) combined cycle by five years.

5. What is the most the company should pay to the power producer for the purchase of five years of combined cycle capacity? Remember that the company could have constructed the combined cycle itself.

The economic value of buying power from the power producer would be the value of deferring the construction of its own facility by five years. The company has two alternatives, which are displayed on Exhibit 3. Although the combined cycle plants both have 30 year lives, the two alternatives are dissimilar since Alternative B (buy combined cycle power for five years, then build a combined cycle) has five more years of combined cycle power (in years 31 through 35) than Alternative A. In addition, the cost of constructing the combined cycle in Alternative B would be higher than the cost of constructing it earlier under Alternative A due to construction cost escalation.

To compute the maximum amount the company should pay for the purchase of the combined cycle capacity for five years, we make these four assumptions:

1. Under each alternative (A or B) the combined cycle will require replacement-in kind at the end of its life.
2. The cost of construction escalates at a rate equal to i_c.
3. The annual discount rate is equal to the after-tax weighted cost of capital, r.
4. $r > i_c$.

With these assumptions, one can construct two infinite streams of combined cycle investments, one for Alternative A and one for Alternative B. The two series are displaced by five years in this example, but for generality, call this displacement period “D” years. Exhibit 4 shows the two infinite series for an initial investment of “$I” in year 0, along with replacement-in-kind investments at the end of the investment life of “L” years. The investment in subsequent periods escalates, so that a general expression for the investment in year nL (where n = 1, 2, 3, etc.) is:

$$I_{nL} = I\,(1+ i_c)^{nL} \qquad (1)$$

The present value of (capital-related) revenue requirements for an investment of $I is equal to KI, where:

K = the present value of carrying charges of $1.00 of investment over L years, with carrying charges assumed to be paid at the end of the year.

For the data shown on Exhibit 2, K is equal to 1.3828.

For **Alternative A**, the present value of the infinite stream of investments to the beginning of year 1 is:

$$PVRR_A = KI + KI\,[(1+ i_c)/(1+r)]^L + KI\,[(1+ i_c)/(1+r)]^{2L}\ldots \qquad (2)$$

This expression simplifies to:

$$PVRR_A = KI \sum_{n=0}^{n=\infty} [(1+ i_c)/(1+r)]^{nL} \qquad (3)$$

This is a geometrical progression that converges to the following[35]:

$$PVRR_A = KI /\{1-[(1+ i_c)/(1+r)]^L\} \qquad (4)$$

For **Alternative B**, the present value of the infinite stream of investments to the beginning of year 1 is:

$$PVRR_B = KI \sum_{n=0}^{n=\infty} [(1+ i_c)/(1+r)]^{n(L+D)} \qquad (5)$$

or

$$PVRR_B = KI \{[(1+ i_c)/(1+r)]^D /\{1-[(1+ i_c)/(1+r)]^L\} \qquad (6)$$

The difference in the two streams, or $PVRR_A$ minus $PVRR_B$, represents the value of the purchase of CC capacity for D years:

$$\Delta PVRR = PVRR_A - PVRR_B \qquad (7)$$

$$\Delta PVRR = KI \{1- [(1+ i_c)/(1+r)]^D\}/ \{1- [(1+ i_c)/(1+r)]^L\} \qquad (8)$$

Equation (8) represents a lump sum present value associated with deferral of a facility for D years. For the five year combined cycle example, one can now compute the maximum value that the company should pay for power which would allow it to defer its planned unit by five years.

We need to assume some data:

Assume that the combined cycle's installed cost (I) is $650 per kW

[35] Convergence requires that the discount rate r be greater than the rate of construction escalation i_c

Assume that data on Exhibit 2 applies: K = 1.3828, r = 7.92%, and i_c= 2.5%

Substituting these values into equation (8) produces a lump sum present value of $259.44 per kW. In other words, for the use of the combined cycle capacity for five years, the maximum the company should pay would be $259.44 per kW, paid at the beginning of the five-year term.

The company could also pay an amount equal to a stream of escalating payments, made at the end of each year, which have the same present value as the lump sum payment. This stream is shown below on the right column.

			Year	Annual $
i_{c} =	2.50%			
r =	7.92%		1	$61.91
K =	1.3828		2	$63.46
I =	$650	/kW	3	$65.05
D =	5	yrs.	4	$66.67
L =	30	yrs.	5	$68.34
ΔPVRR =	**$259.44**	/kW	PV =	**$259.44**

The annual payments increase at the rate of construction escalation. The first year's payment is equal to the value of deferral for D= 1, future-valued to the end of year one. The following formula puts the first year payment on an economic carrying charge basis so that ECC_1 times the investment I equals the first year payment:

$$ECC_1 = (\Delta PVRR_{D=1})/I]\ (1+r) \qquad (9)$$
$$ECC_1 = K\ \{1- [(1+ i_c)/(1+r)]\}/\ \{1- [(1+ i_c)/(1+r)]^L\}(1+r) \qquad (10)$$

For the values above, ECC_1 = .09525, or 9.2525 %. $ECC_2 = ECC_1(1+ i_c)$, etc.

The result is very convenient for assigning an economic value to a capital investment that has only part of its life in the analysis. In the example above, a five-year deferral was considered, but the five-year stream of payments give the value of the investment for deferrals from one to five years. Exhibit 5 shows the economic carrying charges compared to the year-by-year annual charges as well as the levelized revenue requirements. The levelized carrying charge is only appropriate for evaluating alternatives that have equal lives which are totally within the analysis period, while the economic carrying charge is appropriate for evaluating alternatives with either equal or unequal lives even when portions of their lives are outside the analysis period.

Modeling Applications

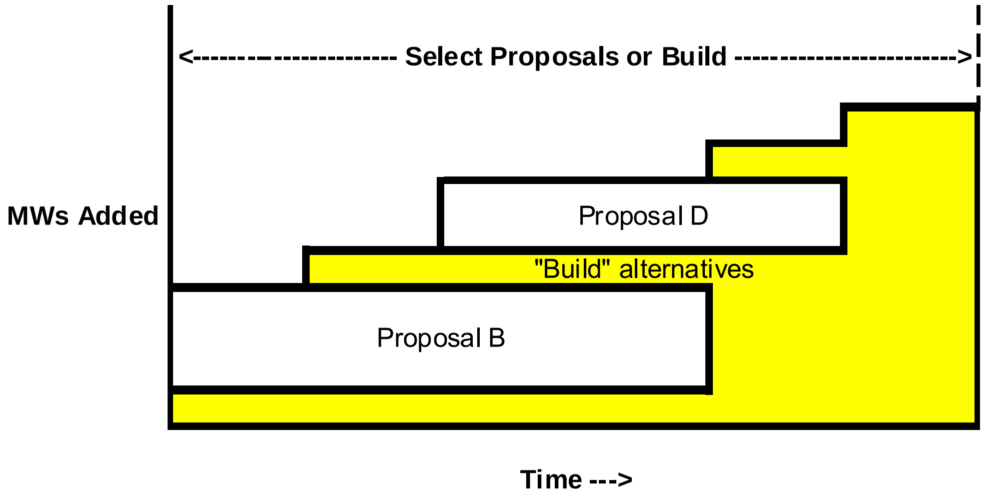
Returning to the original issue described in Exhibit 1, if the economic carrying charge is used to model the capital-related revenue requirements of build alternatives, then the truncation "problem" goes away since each alternative will be assigned the "economic" cost associated with its use for the period of time that it operates in the analysis period.

The concept of an economic carrying charge has application outside the modeling context. In contracting for power, several states define the payment streams for capacity purchases of power from qualifying cogeneration and small power production facilities[36] by the economic carrying charge of the "build" unit that the purchase is avoiding. Contracts with capacity payments that exceed those defined by the economic carrying charge often require some form of security for the differential.

[36] Such facilities are defined in the Public Utility Regulatory Policies Act, or PURPA.

Exhibit 1

a. Analysis That Competes Proposals and Build Alternatives



b. Analysis That Considers Proposals Only, then Builds Alternatives to Fill In Capacity Need

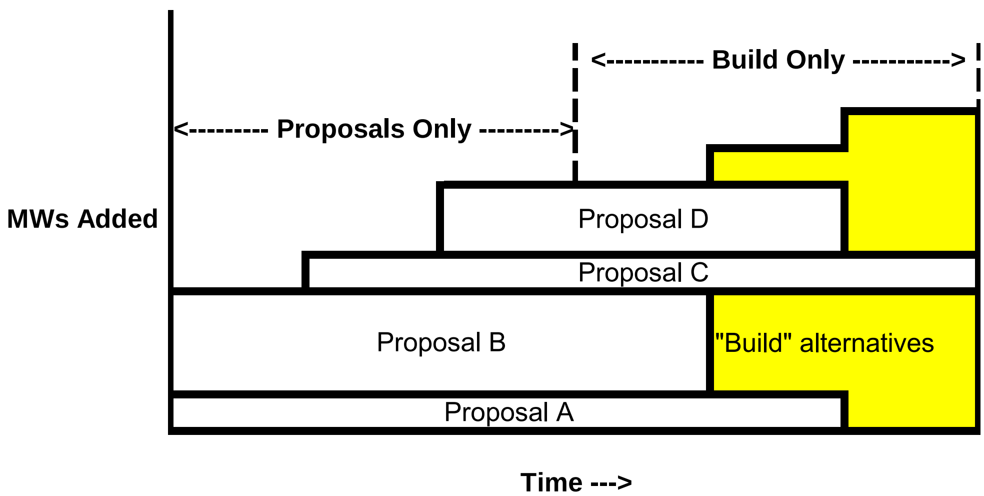


Exhibit 2

Revenue Requirements Calculation for a Capital Investment

	Inputs=		BEFORE TAX WEIGHTED COST	AFTER TAX WEIGHTED COST
COST OF CAPITAL:	RATIO (%)	COST (%)		
DEBT:	60.00%	8.00%	4.80%	3.12%
PREFERRED:	0.00%	0.00%	0.00%	0.00%
COMMON:	40.00%	12.00%	4.80%	4.80%
			9.60%	7.92%

PROPERTY TAX RATE:	1.00%	BOOK LIFE (yrs)	30	<= 30
INSURANCE COST RATE:	0.50%	TAX LIFE (yrs)	20	<= 30
REVENUE TAX RATE:	0.00%	INFLATION RATE	2.50%	used for ECC calc
EFFECTIVE INCOME TAX RATE:	35.00%			

YR	GROSS PLANT	ACCUM DEPR	ACCUM DEF TAX	EOY RATE BASE	BOOK DEPR	DEBT RETURN	EQUITY RETURN	CURRENT TAXES	DEF TAXES	PROP TAXES	INSUR-ANCE	REVENUE REQMT	REVENUE TAX	TOTAL REVENUE REQMT	YR
0															
1	100.00	3.33	0.15	96.52	3.33	4.63	4.63	2.35	0.15	1.00	0.50	16.59	0.00	16.59	1
2	100.00	6.67	1.51	91.83	3.33	4.41	4.41	1.01	1.36	1.00	0.50	16.02	0.00	16.02	2
3	100.00	10.00	2.68	87.32	3.33	4.19	4.19	1.09	1.17	1.00	0.50	15.47	0.00	15.47	3
4	100.00	13.33	3.67	83.00	3.33	3.98	3.98	1.15	1.00	1.00	0.50	14.95	0.00	14.95	4
5	100.00	16.67	4.50	78.83	3.33	3.78	3.78	1.20	0.83	1.00	0.50	14.44	0.00	14.44	5
6	100.00	20.00	5.19	74.81	3.33	3.59	3.59	1.25	0.68	1.00	0.50	13.95	0.00	13.95	6
7	100.00	23.33	5.73	70.94	3.33	3.40	3.40	1.29	0.54	1.00	0.50	13.48	0.00	13.48	7
8	100.00	26.67	6.15	67.19	3.33	3.22	3.22	1.32	0.42	1.00	0.50	13.02	0.00	13.02	8
9	100.00	30.00	6.54	63.46	3.33	3.05	3.05	1.25	0.39	1.00	0.50	12.57	0.00	12.57	9
10	100.00	33.33	6.94	59.73	3.33	2.87	2.87	1.15	0.39	1.00	0.50	12.11	0.00	12.11	10
11	100.00	36.67	7.33	56.00	3.33	2.69	2.69	1.05	0.39	1.00	0.50	11.66	0.00	11.66	11
12	100.00	40.00	7.73	52.27	3.33	2.51	2.51	0.96	0.39	1.00	0.50	11.20	0.00	11.20	12
13	100.00	43.33	8.12	48.54	3.33	2.33	2.33	0.86	0.39	1.00	0.50	10.75	0.00	10.75	13
14	100.00	46.67	8.52	44.82	3.33	2.15	2.15	0.76	0.39	1.00	0.50	10.29	0.00	10.29	14
15	100.00	50.00	8.91	41.09	3.33	1.97	1.97	0.67	0.39	1.00	0.50	9.84	0.00	9.84	15
16	100.00	53.33	9.31	37.36	3.33	1.79	1.79	0.57	0.39	1.00	0.50	9.39	0.00	9.39	16
17	100.00	56.67	9.70	33.63	3.33	1.61	1.61	0.47	0.39	1.00	0.50	8.93	0.00	8.93	17
18	100.00	60.00	10.10	29.90	3.33	1.44	1.44	0.38	0.39	1.00	0.50	8.48	0.00	8.48	18
19	100.00	63.33	10.49	26.18	3.33	1.26	1.26	0.28	0.39	1.00	0.50	8.02	0.00	8.02	19
20	100.00	66.67	10.89	22.45	3.33	1.08	1.08	0.19	0.39	1.00	0.50	7.57	0.00	7.57	20
21	100.00	70.00	10.50	19.50	3.33	0.94	0.94	0.89	-0.39	1.00	0.50	7.21	0.00	7.21	21
22	100.00	73.33	9.33	17.33	3.33	0.83	0.83	1.61	-1.17	1.00	0.50	6.95	0.00	6.95	22
23	100.00	76.67	8.17	15.17	3.33	0.73	0.73	1.56	-1.17	1.00	0.50	6.68	0.00	6.68	23
24	100.00	80.00	7.00	13.00	3.33	0.62	0.62	1.50	-1.17	1.00	0.50	6.42	0.00	6.42	24
25	100.00	83.33	5.83	10.83	3.33	0.52	0.52	1.45	-1.17	1.00	0.50	6.15	0.00	6.15	25
26	100.00	86.67	4.67	8.67	3.33	0.42	0.42	1.39	-1.17	1.00	0.50	5.89	0.00	5.89	26
27	100.00	90.00	3.50	6.50	3.33	0.31	0.31	1.33	-1.17	1.00	0.50	5.63	0.00	5.63	27
28	100.00	93.33	2.33	4.33	3.33	0.21	0.21	1.28	-1.17	1.00	0.50	5.36	0.00	5.36	28
29	100.00	96.67	1.17	2.17	3.33	0.10	0.10	1.22	-1.17	1.00	0.50	5.10	0.00	5.10	29
30	100.00	100.00	0.00	0.00	3.33	0.00	0.00	1.17	-1.17	1.00	0.50	4.83	0.00	4.83	30

	BOOK DEPR	DEBT RETURN	EQUITY RETURN	CURRENT TAXES	DEF TAXES	PROP TAXES	INSUR-ANCE	REVENUE REQMT	REVENUE TAX	TOTAL REVENUE REQMT
PRESENT VALUE (@ 7.92%) =	37.81	32.88	32.88	13.12	4.58	11.34	5.67	138.28	0.00	**138.28**
LEV FIXED CHG RATE 7.92%) =	3.33	2.90	2.90	1.16	0.40	1.00	0.50	12.19	0.00	**12.19**

Exhibit 3

Two Decision Alternatives

	Description
Alternative A	Build CC plant for in-service immedictely
Alterantive B	Buy CC power for five years, build CC plant for service in year 6

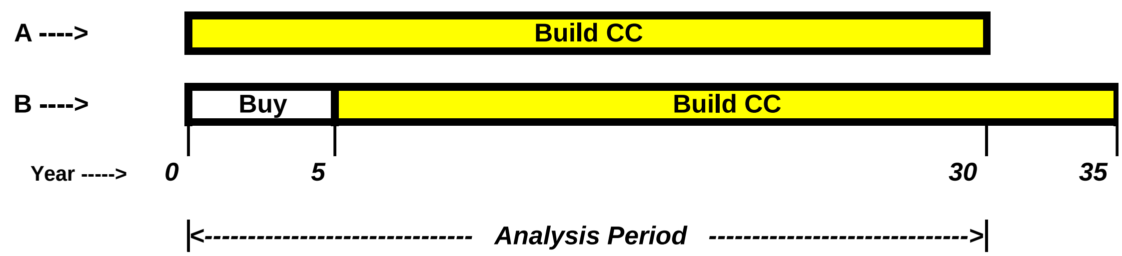
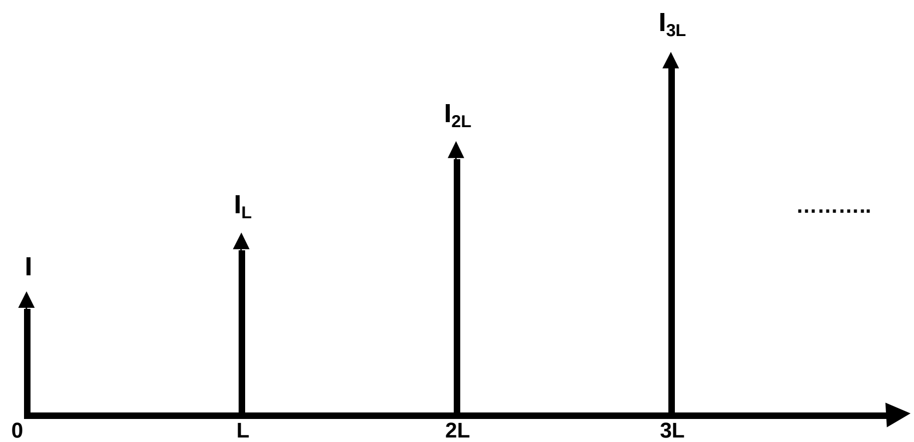
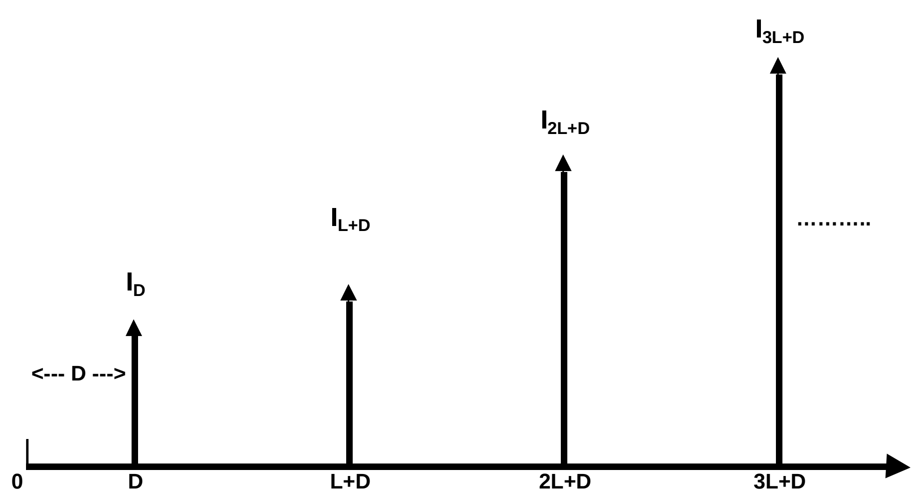


Exhibit 4



Alternative A Investment Stream



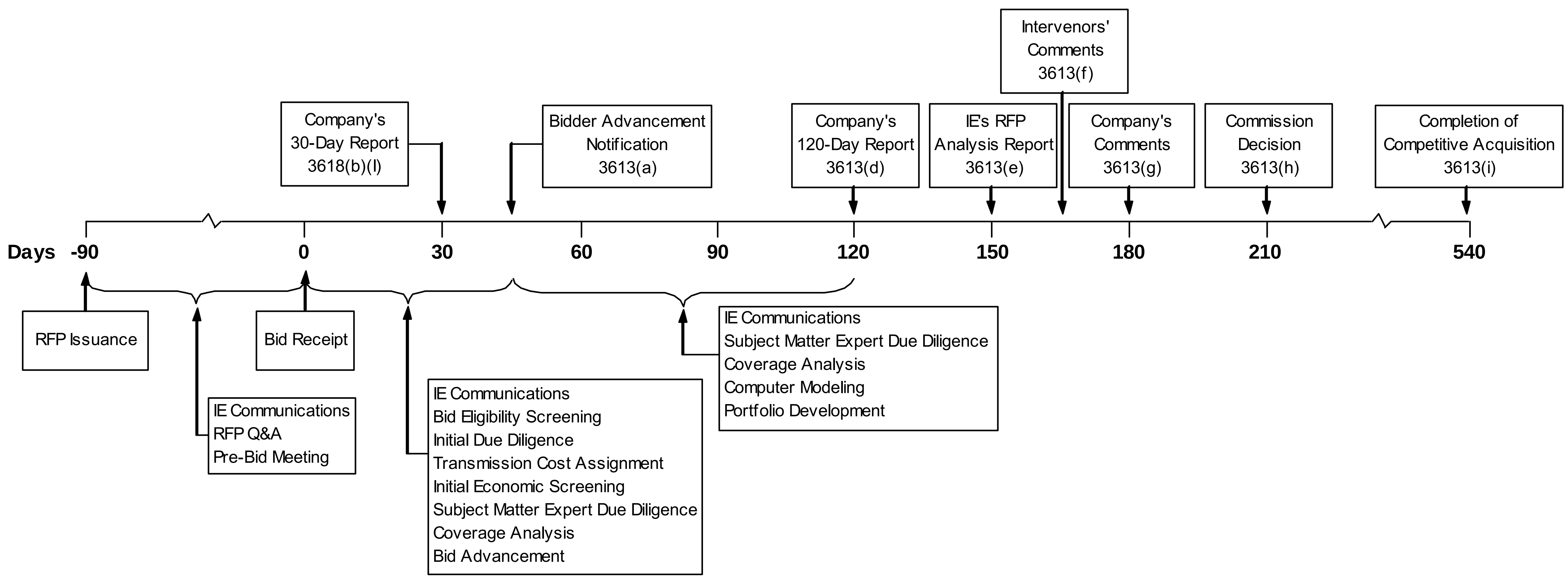
Alternative B Investment Stream

2.9 PHASE 2 BID EVALUATION

The Company proposes to acquire additional generation resources to meet the RAP needs through an All-Source Solicitation or RFP. In Decision No. C11-0810, the Commission altered its ERP Rules; notable among these alterations were changes to ERP Rule 3613, Bid Evaluation and Selection. Information in this section is intended to illustrate how the Company will manage the receipt and evaluation of bids pursuant to the new ERP Rules.

Figure 2.9-1 presents a timeline of All-Source Solicitation activities with citations to ERP Rule requirements.

Figure 2.9-1 Phase 2 Timeline



All-Source RFP Release and Initial Bid Due Diligence

Company Activities Preceding the Release of the RFP

Public Service will create a webpage on the Xcel Energy website[37] dedicated to the All-Source RFP. Prior to the release of the RFP, the Company will assign an individual to serve as the RFP Manager; this individual will serve as the primary point of contact for communications between the Company and its due diligence teams and the bidders.

Company Activities Following the Release of the RFP

The Company anticipates issuing the All-Source RFP approximately 90 days in advance of the Bid Receipt date. As filed in Volume 3 of this 2011 ERP, the Company is proposing three (3) distinct requests for proposals (RFPs): 1) a Dispatchable Resources RFP, 2) a Renewable Resources RFP, and 3) a Semi-Dispatchable Renewable Capacity Resources RFP. Official versions of the RFP documents (the RFP document, a model purchased power agreement, and bid submission forms) will be posted to the RFP webpage on the day of the RFP release.

ERP Rule 3616(d) requires the Company to provide potential bidders with a copy of the Commission's order or orders specifying the form of nondisclosure agreement necessary to obtain access to confidential and non-confidential modeling inputs and assumptions provided by the Company pursuant to ERP Rule 3613(b). The nondisclosure agreement will be included in the RFP bid submission forms once these forms have been approved by the Commission. ERP Rule 3616(d) also requires the Company to provide potential bidders an explanation of the process by which disputes regarding inputs and assumptions to computer-based modeling will be addressed by the Commission pursuant to ERP Rule 3613(b). This explanation can be found in Section 1.1 of the Dispatchable Resources RFP, the Semi-Dispatchable Renewable Capacity Resources RFP, and the Renewable Resources RFP.

ERP Rule 3616(e) directs the Company to require bidders to provide the contact information of a person designated to receive a notice pursuant to ERP Rule 3613(a). Language directing the bidder to provide this information is on Form C of the model bid submission forms. ERP Rule 3616(f) requires the Company to inform bidders that information for all bids submitted in response to the RFP will be made available to the public through posting of the bid information on the Company's website upon the completion of the competitive acquisition process pursuant to ERP Rule 3613(i). This information can be found in Section 1.1 of the model RFP documents.

[37] www.xcelenergy.com

The Company anticipates that it will hold a Pre-Bid Meeting approximately three (3) weeks following the issuance of the All-Source RFP. In addition to the Pre-Bid Meeting, the Company will directly respond to potential bidder questions submitted via email. Non-confidential Q&A versions of issues raised during the Pre-Bid Meeting as well as from questions submitted via email will be posted to the Q&A document on the All-Source Solicitation webpage. The Independent Evaluator will be copied on all emails sent directly to potential bidders.

Bid Receipt and Generation Technology Categorization

The Company will request both hard copy and electronic versions of proposals; copies of the bid submission materials will be provided to the Independent Evaluator and to Commission Staff. Upon receipt of the bids, the Company will conduct an initial review to categorize the bid by its proposed generation source with bids employing similar technologies. Such an initial categorization simplifies downstream due diligence and economic evaluations and is necessary to comply with ERP Rule 3618(b)(I) regarding the 30-day report.

Bid Eligibility Screening and Initial Due Diligence

Once the bids have been catalogued, the Company will conduct a review of each bid to ensure that the proposed project meets the minimum bid eligibility requirements. Each of the three RFPs have slightly different minimum bid eligibility requirements corresponding to the different technologies targeted by the RFPs; specific details on the minimum bid eligibility requirements are laid out in the respective model RFP documents in Volume 3.

The Company intends to limit the total MW size of any single PV facility bid into the All-Source RFP to a maximum of 50 MW AC. For purposes of calculating this 50 MW limitation, the Company will consider PV projects within 5 miles of another plant (existing or proposed) as a single facility.[38] This limitation is based on the Company's on-going monitoring of the real-time generation from the SunE Alamosa 1 (~7 MW AC) and Greater Sandhill (~18 MW AC) projects in the San Luis Valley (as well as its real-time monitoring of five (5), 10 MW facilities in New Mexico) and concerns as to the incremental impact of the two, 30 MW facilities currently under construction in the San Luis Valley. The Company is concerned that it may not have sufficient spinning reserves available to handle the rapid swings in real-time generation exhibited by these facilities when they occur concurrently with load swings induced by the steel mill arc furnace in Pueblo.[39] As the Company cannot currently predict the amelioration of PV ramp rates due to the

[38] For illustration purposes, the maximum size of a new PV facility within 5 miles of the 30 MW Cogentrix facility would be 20 MW AC.

[39] Conversely, the Company cannot currently estimate the integration costs that should be applied to PV bids that could significantly increase the Company's spinning reserve costs.

geographic diversity of the two, 30 MW projects under construction,[40] it feels it is prudent based on system reliability issues to impose this system size limit at this time. At the time of the RFP issuance, the Company should have roughly 9 months of experience with all four San Luis Valley PV systems (~ 85 MW AC total) operational and may be in a better position to relax or tighten this limitation on maximum facility size or geographic location.

The Company intends to notify all RFP respondents within 15 days of bid receipt as to the Company's bid eligibility evaluation.

At the time that the Company conducts its bid eligibility screening, it will also conduct an initial due diligence review of the bids. This initial due diligence review is intended to quickly identify any potential fatal flaws or conceptual misunderstandings as to the proposed project. To the extent the Company requires additional information from the bidder as a result of its initial due diligence, it will contact the bidder promptly and ensure that the Independent Evaluator receives a copy of the request for additional information as well as a copy of the bidder's reply.

Initial Bid Economic Analysis and Bid Screening

Assignment of Transmission Interconnection and Network Upgrade Costs

One of the bid eligibility requirements is that the project function as a network resource, i.e., capacity and energy from the proposed generation project must be delivered to the Company's electric transmission or distribution system at a location such that the capacity and energy can then be delivered to the Company's customers. The Company will assign incremental transmission interconnection costs and/or network upgrade costs to each bid, as appropriate. Transmission associated capital costs will be converted to annual levelized costs utilizing a levelized fixed charge rate ("LFCR") of 0.12 for inclusion in the initial economic screening.

Consistent with prior acquisition evaluations, the Company will not assign network upgrade costs to any project that utilizes a transmission upgrade for which the Company has received a CPCN; provided, however, that sufficient transmission transfer capability exists on the transmission project specified in the CPCN after accounting for other generation projects. Because Commission Decisions granting a CPCN for the San Luis Valley – Calumet – Comanche transmission line have been appealed to the state courts, bids that are dependent upon the construction of that new transmission facility will be assigned incremental interconnection and network upgrade costs.

[40] The San Luis Solar facility is located ~ 1 mile from the SunE and Greater Sandhill facilities and the Cogentrix Alamosa facility is located ~ 6 miles from the SunE, Greater Sandhill, and San Luis Solar facilities.

Existing generation resources from which the Company currently purchases capacity and energy will not be burdened with any incremental electrical transmission interconnection or network upgrade costs.

Initial Economic Screening

The initial economic screening consists of calculating an "all-in" levelized cost of energy ("LEC"). LECs are calculated as the present value of the sum of the total costs and benefits for each year of the proposed project's term divided by the present value of the estimated annual energy streams.[41] Present values are calculated as of the project's in-service year to avoid confusing the inherent value of delay with true differences in LEC. The Company will employ its after tax WACC in the present value calculations.

The term "all-in" refers to the inclusion of all costs and benefits associated with the project, e.g., wind integration costs for wind bids or fixed and variable costs at a specified annual capacity factor for dispatchable bids. Projects that propose to interconnect at distribution voltages will be credited with avoided line losses in their LEC calculations. The result of this credit is that the LEC for a distribution-interconnected project will be lower than that for an identical, transmission-interconnected project by the avoided line losses.

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Initial economic screening (i.e., LEC calculations) will be conducted directly within the bid submission forms supplied by the bidders.[42] The Company will make several adjustments to the LEC calculation inputs, as necessary, including, but not limited to:

- the Company's final natural gas forecast,
- the Company's estimates of fuel delivery costs on both an interruptible and a firm basis, where applicable,
- the Company's estimates of any incremental transmission interconnection or network upgrade costs,
- adjustments to estimated performance or pricing levels that result from the Company's due diligence efforts and/or updated information received from the bidder.

No renewable energy credit ("REC") value benefits will be credited to the LEC calculations for any renewable generation projects.

Outside of these general observations, specific costs and benefits will be assessed to bids employing certain generation technologies as detailed below.

[41] See Section 2.8 above for sample LEC calculations for a gas-fired combined cycle proposal and an energy only (e.g. wind) proposal.

[42] LEC calculations can be seen on the "LEC" tab of the RFP Forms in Volume 3.

Wind LEC Calculations

Wind bids will be burdened with:

- Wind integration costs based on the bid MW over and above the acquired wind base of 2,125 MW.[43] Annual wind integration costs will be adjusted by the annual gas curve as indicated in the Company's 2GW and 3GW Wind Integration Cost Study.[44]
- Coal cycling costs based on the bid MW. Both the cycling and curtailment cost components from the Company's Coal Plant Cycling Cost and Implications of Wind Curtailment Study will be imposed for purposes of bid screening.[45]

Solar LEC Calculations

Solar bids, e.g., PV and solar thermal with no storage capability, will be burdened with:

- Solar integration costs based on the Company's most recent solar integration study.[46]

Base Load Renewable LEC Calculations

Base load renewable generation resources include technologies such as biomass, geothermal, and hydro. In general, these are non-dispatchable renewables in which an expectation of significant generation during off-peak hours is justified. These types of bids will be burdened with:

- Both the cycling and curtailment cost components from the Company's Coal Plant Cycling Cost study.

Semi-Dispatchable Renewable Capacity LEC

No incremental costs or benefits will be assessed in the calculation of a semi-dispatchable renewable capacity project's LEC.

Stand-alone Storage LEC

Stand-alone storage bids will be provided with a wind integration cost credit to the portfolios in which they exist as quantified in the Company's 2 GW and 3 GW Wind Integration Cost Study. In order to estimate this credit in an LEC calculation, the Company will assume a base level of 2,125 MW of wind.

The Company is also investigating whether the model used to evaluate coal cycling costs can be enhanced to investigate the potential benefits that incremental energy storage might have in reducing estimated coal cycling costs.

[43] 2,125 MW of installed wind assumes that the Commission approves the Company's request in Docket No. 11A-689E for the acquisition of 200 MW of incremental wind generation from the Limon II wind facility.

[44] See Table 14 on page 23 of the 2GW and 3GW Wind Integration Cost Study (Attachment 2.13.1).

[45] See Table 2 on page 17 of the Wind Induced Coal Plant Cycling Costs Study (Attachment 2.12.1).

[46] See the Solar Integration Study filed with the Commission on February 10, 2009 in Docket No. 07A-447E.

Gas-Fired, Dispatchable LEC

LECs for dispatchable generation resources are calculated by converting the fixed costs to variable costs by assuming an annual capacity factor and by assuming an average annual heat rate with which to estimate fuel volumes and costs. Gas-fired, peaking resources will be screened with an assumption of a 5% annual capacity factor. Gas-fired, intermediate resources will be screened with an assumption of a 40% annual capacity factor. The average annual heat rate utilized in the LEC calculations will be the average of the seasonal full load heat rates (without supplemental capacity) supplied in the bid forms.

Start charges are converted to a variable $/MWh cost by assuming a set number of hours that a unit will run at full output once started; full output is defined as the net capability of the unit without supplemental capacity; e.g., duct firing on a combined-cycle power plant. For peaking resources, the Company assumes a four (4) hour run time per unit. For intermediate resources, the Company assumes a twelve (12) hour run time per unit and that all CTs are started, e.g., two (2) turbines started for a 2x1 CC facility.

To the extent a project proposes to wheel capacity and energy across another utility's transmission system prior to delivery to the Company's system, estimated wheeling losses will be imposed against the full load heat rate which will effectively increase the variable cost component of the LEC. Such an adjustment is necessary since the heat rates are calculated at the generation unit (which resides on another utility's system), whereas the other components of the LEC are all based on capacity and energy delivered to the Company's system.

No incremental benefits for quick start or faster ramp rates are provided in the LEC calculations.

Subject Matter Expert Due Diligence

Subject matter experts typically include, but are not limited to, Company personnel from the following organizations:

- Transmission Access
- Generation Resource Planning
- Transmission Planning
- Natural Gas Planning
- Commercial Operations
- Purchased Power
- Credit
- Tax
- Accounting
- Environmental Permitting

- Energy Supply
- Siting and Land Rights

Each department conducts its due diligence reviews in the manner they determine best. In the event that subject matter experts require additional information or clarification on certain aspects of a bid, those requests will be forwarded to the bidders by the RFP Manager. Each bid reviewed by each department will result in a written due diligence report with an indication as to the feasibility of the project's ability to meets its proposed in-service date with the selected technology and proposed performance levels.

The Company reserves the right to employ outside technical experts to review bids to the extent the Company believes such analyses are warranted to sufficiently review any proposal.

30 Day Bid Summary Report (ERP Rule 3617(b)(I))

Pursuant to ERP Rule 3618(b)(I), the Company will report to the Commission within 30 days of bid receipt on the following topics:

- Bidder identity
- # of bids received (total and by resource type)
- MW (total and by resource type)
- Description of prices (by resource type)
- Whether or not the Company believes it needs to implement its contingency plan

Secondary Economic Screening

Any adjustments to bid information that impacts a bid's LEC following the completion of the subject matter experts' due diligence efforts will be incorporated into a final LEC calculation. Based on the final LEC calculations, all bids utilizing similar technologies will be sorted by LEC and by proposed in-service dates.

Assessment of Arapahoe 4 and Cherokee 4 on Gas

Background

Continued operation of these two facilities on natural gas was approved by the Commission in the CACJA proceeding (Docket No.10M-245E) for emission reduction purposes. At the time of the CACJA proceeding, the Company's transmission analyses indicated that in order to maintain acceptable transmission reliability it was necessary to 1) maintain three sources of power at Cherokee of which two sources needed to be generators capable of producing real power at the Cherokee site (considering the 2x1 CC as one unit) and 2) impose a "must run" requirement on the fuel switched Cherokee 4 unit of approximately 40% annual capacity factor. Since that time the Company has continued to study the issue and its most recent transmission studies indicate 1) while still preferable, two sources of real power are not required at the Cherokee site (again considering the 2x1 CC as one unit) and 2) the fuel switched Cherokee 4 unit will not have a minimum "must run" requirement for transmission reliability purposes. The practical result of these findings is that power supply proposals from facilities located at sites other than Cherokee can be considered as potential alternatives to the 352 MW Cherokee 4 unit operating on natural gas so long as these alternatives meet or exceed the emission reductions achieved by burning gas in Cherokee 4. The other practical result is that the Company need not assume Cherokee 4 is a must run unit; instead, Cherokee 4 can be economically dispatched.

Regarding Arapahoe 4, the most recent transmission studies indicate that maintaining generation at the Arapahoe site (either Arapahoe 4 or Southwest Generation's Arapahoe 5, 6, 7 units) is <u>not</u> necessary for transmission reliability purposes. The practical results of this finding are 1) power supply proposals from facilities located at sites other than Arapahoe can be considered as potential alternatives to the 109 MW Arapahoe 4 unit operating on natural gas so long as these potential alternatives meet or exceed the emission reductions achieved by burning gas in Arapahoe 4, and 2) the fuel switched Arapahoe 4 unit will not have any minimum "must run" requirements but rather will be allowed to be economically dispatched.

Note that as part of the settlement of the Cherokee Synchronous Condenser CPCN, the Company agreed to perform additional transmission studies before asking the Commission to remove the requirement in Docket No. 10M-245E to convert Arapahoe 3 to a synchronous condenser. That study will be completed by the end of 2012. The Company does not think that study will materially impact the conclusions reached here that Cherokee 4 and Arapahoe 4 do not have minimum operating requirements and can be replaced with generation located off of those sites.

<u>Alternatives to Burning Gas in Arapahoe 4 and Cherokee 4</u>

Public Service is proposing that the assessment of potential alternatives to burning gas in Arapahoe 4 and Cherokee 4 be accomplished through a process that will occur prior to the computer modeling of All-Source RFP bid portfolios. This process will utilize bids received in response to the All-Source RFP from existing dispatchable gas-fired generation facilities offering short-term PPAs as potential alternatives for running Arapahoe 4 and Cherokee 4 on gas. See Section 1.7 of the 2011 ERP Volume 1 for information on the proposed evaluation process. One aspect of the evaluation will involve estimating the operation and maintenance ("O&M") costs for continued operation of these two fuel switched facilities. The Company estimates O&M costs for Arapahoe 4 and Cherokee 4 as well as all of its owned generating units as part of its normal course of business. These analyses involve working directly with the Public Service personnel assigned to operate these facilities to develop estimates for all facets of unit O&M, including but not limited to unit staffing levels, unit utilization, materials and supplies, and anticipated capital investments needed to maintain the facility in good operating condition. These O&M related costs are the costs that potential alternative power supplies will get credit for avoiding within the analysis. Alternative power supplies will not avoid, however, the Company's need to fully recover the remaining undepreciated book value or the costs of removal for Arapahoe 4 and Cherokee 4 facilities. The Company will model the recovery of the undepreciated book value and cost of removal of those plants over their current remaining useful life whether they are retired early or not.

To the extent that a bid or group of bids offered in the All-Source Solicitation is found to be an economically superior option to the continued operation of either Arapahoe 4 or Cherokee 4 on gas, the successful bid(s) will displace either Arapahoe 4 or Cherokee 4 as a base assumption in the computer modeling of bid portfolios discussed below.

Selection of Bids for Computer Modeling

All bids from existing thermal generation resources currently under contract with the Company and all Company self-build projects will be passed through screening to portfolio development. Gas-tolled thermal facilities will be selected for inclusion in computer modeling based on their LEC calculated with an assumption of no incremental firm fuel supply costs. Pursuant to ERP Rule 3616(d) and contingent upon the existence of sufficient bids passing through bid eligibility and due diligence screening, the Company shall pass forward to the portfolio development phase a sufficient quantity of bids across the various generation resource types such that resource plans can be created that conform to the range of scenarios for assessing the costs and benefits from the potential acquisition of increasing amounts of renewable energy resources or Section 123 Resources as specified in the Commission's Phase 1 decision.

To the extent initial Strategist modeling indicates that all bids of a specific generation resource type (e.g., all wind bids) passed to portfolio development appear in the least-cost portfolio(s), additional bids utilizing that generation resource type will be included in subsequent model runs. This iterative process will be followed until no incremental bids employing that generation resource type are selected in the least-cost portfolio. Bidders whose projects are passed forward to portfolio development will be notified of their project's advancement pursuant to ERP Rule 3613(a) and will be provided with the modeling inputs and assumptions for that project pursuant to ERP Rule 3613(b).

Report to Advanced Bidders

Pursuant to ERP Rule 3613(a), 45 days after bids are received the Company will email each bidder and indicate whether its bid has been advanced to computer modeling and portfolio development. For those bids not advanced, the Company will provide the reason(s) why the project will not be evaluated further. For those bids advanced to computer modeling and portfolio development, the Company will provide the modeling inputs and assumptions that reasonably relate to that potential resource or to the transmission of electricity from that facility to the Company.

Computer Modeling and Portfolio Development

Public Service will use the Strategist electric utility planning model to represent the various costs of the least-cost baseline case and all alternative plans in Phase 1 of the 2011 ERP as described in Section 2.8 above. Strategist will also be used in developing portfolios of bids that are advanced to this stage of the All-Source Solicitation bid evaluation. The modeling framework Public Service will employ in the Phase 2 portfolio modeling is the same as that used to develop the least-cost baseline case and alternative plans with two exceptions: 1) actual bids are used to meet RAP needs instead of generic estimates and 2) the lowest cost Company self-build proposals will make up the "baseline case" RAP resources that are used to fill-in as needed to meet capacity requirements when bids expire or a portfolio does not meet capacity and reserve margin requirements.

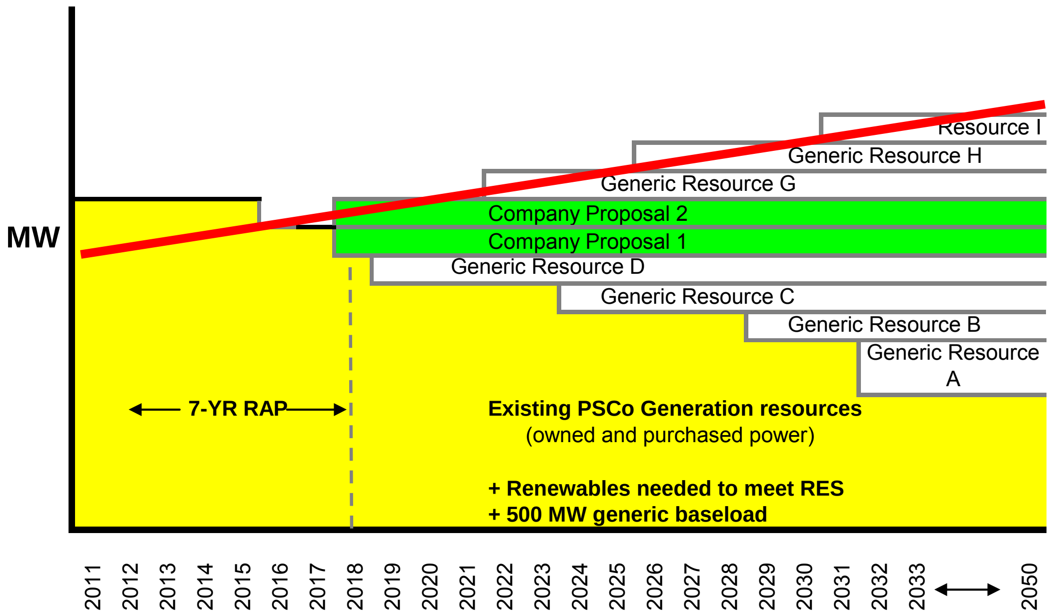
Development of a Least-Cost Self-Build Portfolio

After constructing an updated base Strategist model representation of the Public Service electric system, the Company will develop a least-cost portfolio that meets the updated RAP capacity needs with Company-owned proposals received in response to the All-Source RFP. To the extent that the Company is unable to provide bids for sufficient resources to fill an entire portfolio, the Company may supplement the bids with the most up-to-date generic resource bids as needed to fill the capacity need to develop a Self-build portfolio. Resource needs beyond the RAP will be modeled using generic resources in the same manner used in developing the Alternative Plans discussed in Section 2.8. This portfolio of least-cost Company self-build proposals will be used to extend all other bids to the end of the Planning Period or when a portfolio of bids does not fully meet capacity and reserve margin requirements.

Company proposals will include the same costs or benefits as those applied in the initial economic screening of bids described earlier in this Section. Company proposals will be modeled using traditional capital revenue requirements when reporting annual total system costs. During optimization and ranking of various portfolios of resources, Strategist will use an Economic Carrying Charge ("ECC") representation of costs.[47] Since the useful lives of Company proposals will extend through the end of the Planning Period, no assumptions need be made on how to extend the lives of Company proposals. Figure 2.9-2 illustrates how the least-cost Self-Build portfolio is developed. Surplus capacity will be credited at the short-term capacity purchase price of $2.79/kW-mo for 4 months through 2018 and then at the ECC price of the Company's least-cost, combustion turbine proposal for years 2019-2050.

[47] See Section 2.8 for an explanation of ECC.

Figure 2.9-2 Least-Cost Company Proposal Portfolio

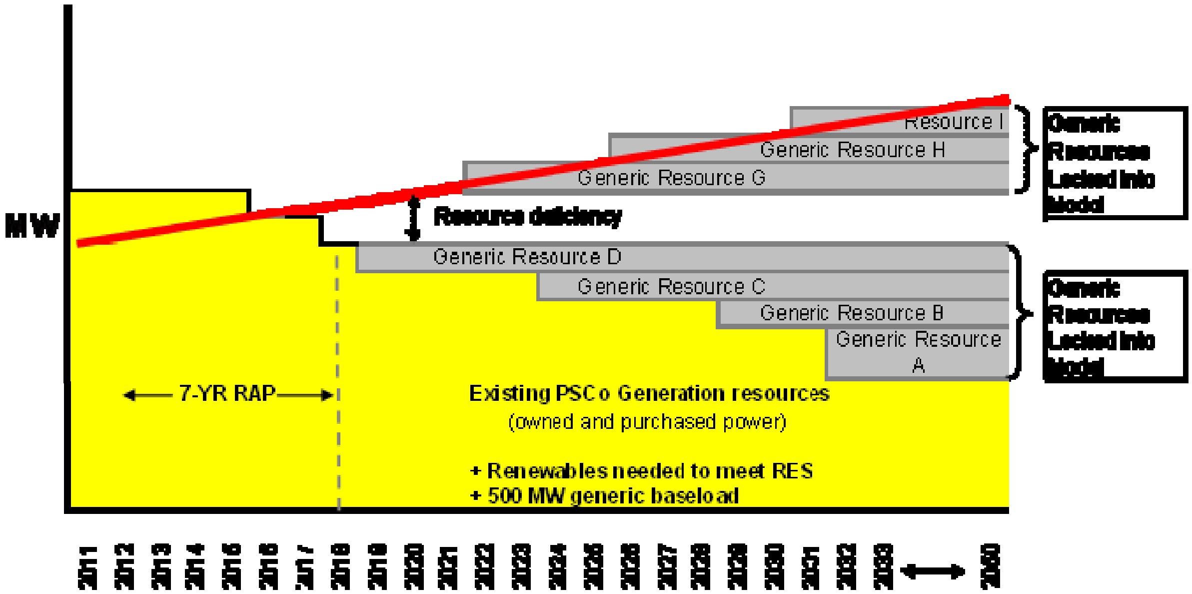


<u>Development of Bid Portfolios</u>

Starting with the least-cost self-build portfolio model, portfolios of bids and Company proposals will be developed that meet the same RAP needs as the least-cost self-build portfolio described above. Portfolios that meet the RAP capacity need utilizing bids that do not extend to the end of the Planning Period will be "backfilled" with the Company proposals that comprise the least-cost self-build portfolio. The Strategist model will be allowed to determine when each of the self-build options is used to perform this backfilling to ensure it is done in a manner that minimizes the PVRR of each portfolio. Since all non-Company bids are limited to a PPA term of 25 years, each portfolio will eventually include all of the self-build proposals included in the least-cost self-build portfolio by the end of the Planning Period.

As discussed earlier, in the computer modeling of all bid portfolios (self-build and other proposals), Public Service will employ a similar modeling convention as that approved by the Commission in Docket No. 07A-447E. All generic resources added in years beyond the RAP (2019-2050) will be locked down in the Strategist model. Note that the term "locked down" refers to the fact that a generic resource is hardwired into the Strategist model to begin its operating life in a specific year as opposed to being modeled in a fashion where it has a floating in-service date that is ultimately selected by the model based on economics. All generic resources "locked down" in the model will still capable of being economically dispatched with the rest of the fleet to meet customer load in a least-cost manner with the exception of wind and solar PV which are not capable of being dispatched. Figure 2.9-3 shows a graphical depiction of the generic resources that are locked down in the modeling.

Figure 2.9-3 Depiction of Strategist Model with Locked-down Resources



Figures 2.9-4(a) and (b) shows two examples of how the least-cost Company self-build proposals may be used to backfill portfolios of bids that expire before the end of the Planning Period. Figure 2.9-4(a) shows a portfolio where the least-cost portfolio includes only bids in the RAP and the least-cost Company proposals filling in the backend when bids expire. Figure 2.9-4(b) shows a portfolio that includes both a Company proposals and bids in the least-cost mix. Because bids are limited to a maximum of a 25 year contract term, all portfolios that contain bids will eventually revert back to the least-cost self-build portfolio by the end of the Planning Period.

Figure 2.9-4(a) Illustration A of a Portfolio of Bids and Company Portfolios

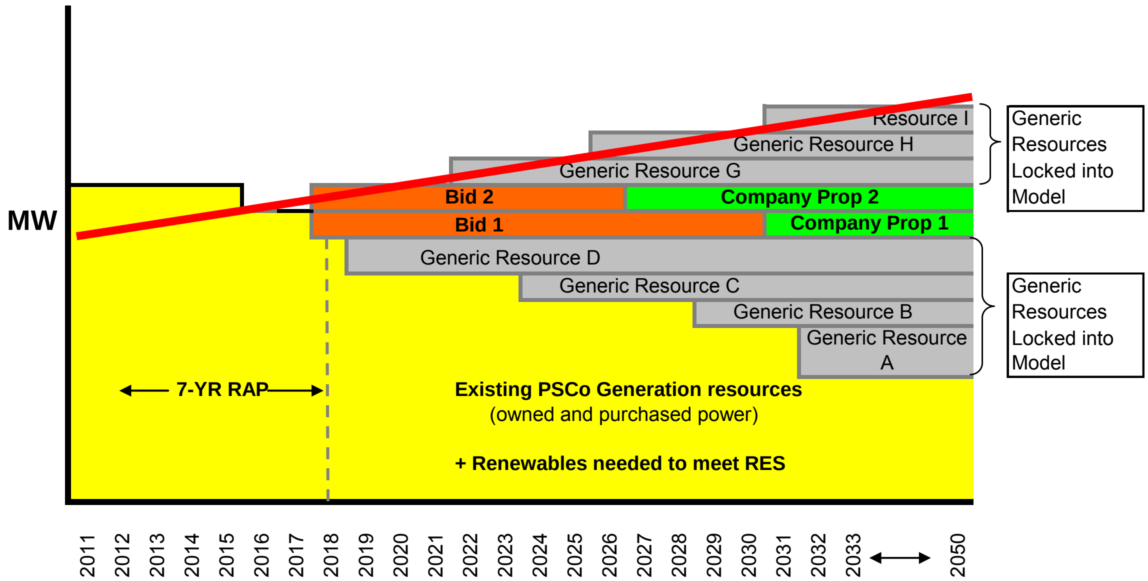
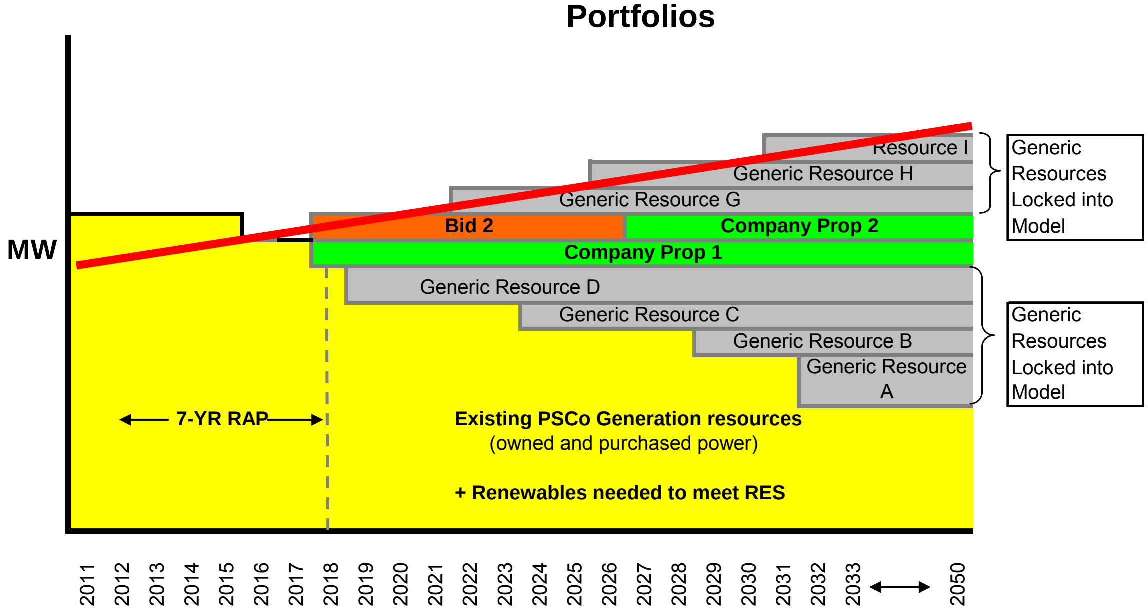


Figure 2.9-4(b) Illustration B of a Portfolio of Bids and Company Portfolios



Since each portfolio reverts back to the least-cost self-build portfolio once the added resources retire, this isolates the evaluation to the impact of the bids themselves. Figures 2.9-5 (a) and (b) illustrate this process. In Figure 2.9-5(a), the blue line represents the costs of the least-cost self-build portfolio with the capital costs shown as an Economic Carrying Charge. The red dashed line represents the costs of a bid portfolio. When the bid retires in this portfolio, the plan reverts back to the costs of the least-cost self-build portfolio. In this example, the bid portfolio is more expensive than the self-build portfolio. Figure 2.9-5(b) shows another illustration but with a bid portfolio being less than the least-cost self-build portfolio.

Figure 2.9-5(a) Comparison of a Bid Portfolio vs. Self-Build Portfolio

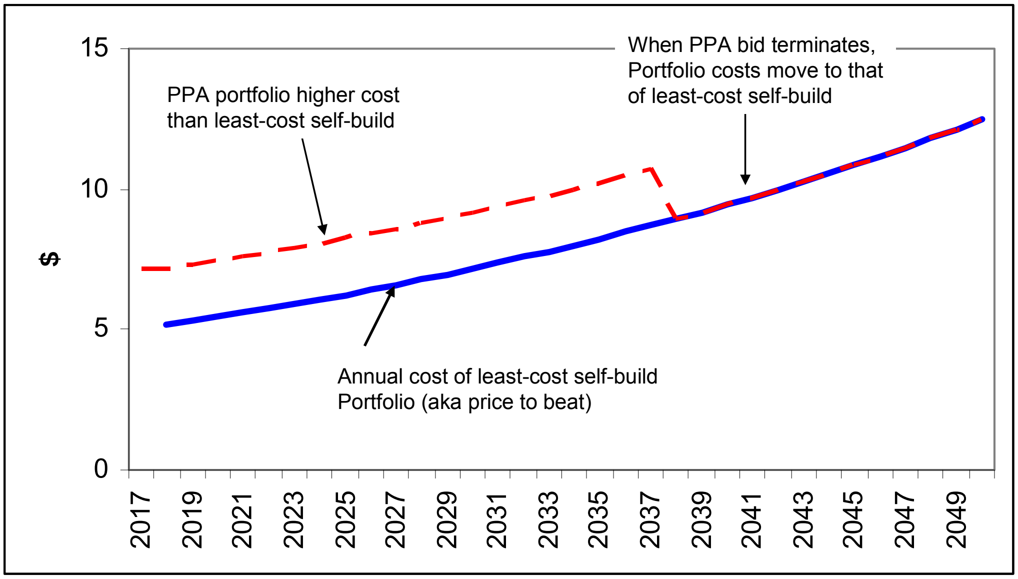
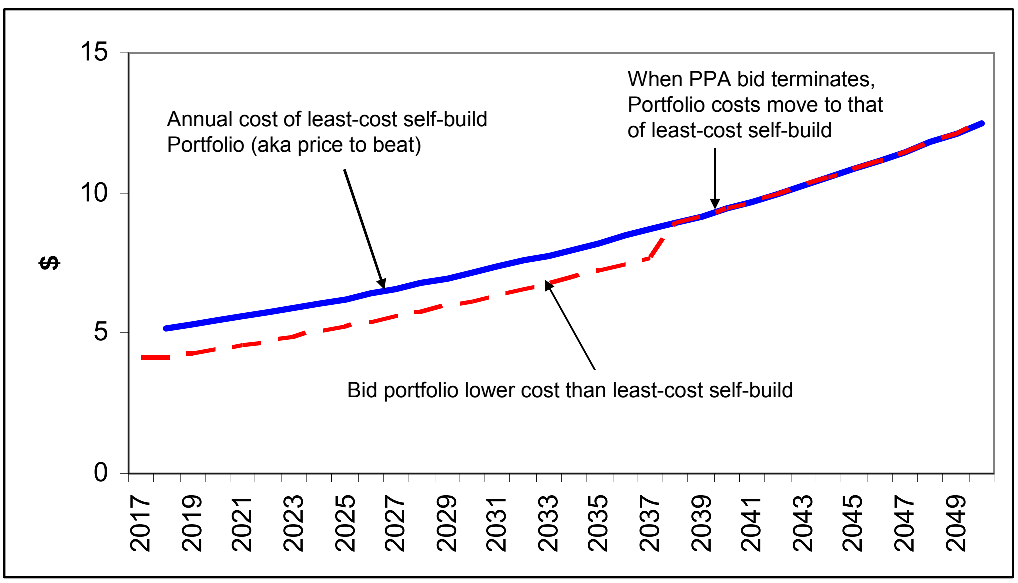


Figure 2.9-5(b) Comparison of a Bid Portfolio vs. Self-Build Portfolio



Selection of Bid Portfolios for Additional Study

A set of portfolios utilizing a range of technologies to meet the RAP needs will be selected for additional analyses involving an assessment of winter generation adequacy as well as input assumption sensitivity analyses. A sufficient number of portfolios will be selected for these additional analyses to ensure a diverse set of generation technologies are represented as well as a diverse set of PPA term lengths as described in Section 1.7 of Volume 1.

Winter Generation Adequacy of Portfolios

In August 2011, FERC issued their "Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011". The FERC task force recommended that "all entities responsible for the reliability of the bulk power system…prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season." The Company is in the process of reviewing its winter season generation reliability and will summarize its findings in a study filed with the Commission as a part of the 2011 ERP process as soon as the review is completed. Each of the bid portfolios selected for sensitivity analyses will be assessed to determine if it meets the generation reliability requirements identified in the Company's "Winter Generation Adequacy Study". To the extent a bid portfolio does not include an adequate level of generation reliability as defined by this study, the Company will estimate the cost associated with actions that could be taken to meet those reliability requirements in the lowest cost manner. The present value of the costs associated with any required actions will be added to the PVRR of the associated portfolio. Additional information regarding this Winter Generation Adequacy Study is included in Attachment 2.9-1.

Sensitivity Analyses of Portfolios

Sensitivity analyses of the selected portfolios will be completed on portfolios that are advanced from the firm fuel supply analysis. Sensitivities will be completed on several key assumptions as follows:

1. Low and High Gas Forecasts
2. CO_2 Proxy Prices Forecasts
3. Wind PTC Extension - Public Service will determine if a sensitivity on the Production Tax Credits on wind bids is warranted. In any solicitation that is part of this resource plan, bidders will be asked to provide both PTC and non-PTC prices in their bids (if warranted).
4. Solar ITC - Public Service will determine if sensitivity on the Investment Tax Credits on solar bids is warranted. In any solicitation that is part of this resource plan, bidders will be asked to provide both 30% ITC and 10% ITC prices in their bids (if warranted, e.g. any bids with a COD past 12/31/2016).
5. Construction Escalation Rates - The Company proposes including a high and low construction escalation rate sensitivity. For these sensitivities, the construction escalation rates of company proposals will be replaced with a low and high construction escalation rate.

Attachment 2.9-1 Winter Generation Adequacy Study

During the winter of 2010-2011, the electric industry experienced significant generation outage events in Texas related to cold weather. On February 14th, the Federal Energy Regulatory Commission ("FERC") initiated a formal inquiry into the generation outages and service disruptions during that cold weather event. In August 2011, FERC issued their "Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011". The FERC task force recommended that "all entities responsible for the reliability of the bulk power system…prepare for the winter season with the same sense of urgency and priority as they prepare for the summer peak season."

Public Service is reviewing its winter operation procedures and resources to ensure that it has adequate cold weather generation available to meet the system needs reliably and will file a Winter Generation Adequacy Study as part of the 2011 ERP with the Commission as soon as the study is complete. Given the termination of several coal-based purchased power contracts, the retirement of Company-owned coal-fired generators, and increased reliance on non-dispatchable generation resources, one key aspect of this study will be an assessment of the generation required to have a firm fuel supply (or adequate onsite backup fuel) to reliably serve peak winter loads. While fuel oil back-up is a firm fuel supply for peaking units under winter or restricted fuel delivery conditions (provided that the primary fuel supply is reliable during most all of the time the resource is expected to operate), the Company's preference for firm fuel supply for thermal units is natural gas.

As explained earlier, each of the bid portfolios selected for sensitivity analyses will be assessed to determine if it meets the generation reliability requirements identified in the Winter Generation Adequacy Study. To the extent a bid portfolio does not include an adequate level of generation reliability as defined by the study, the Company will estimate the cost associated with actions that could be taken to meet those reliability requirements in the lowest cost manner. The assessment of acquiring a firm natural gas supply will recognize that certain projects may be able to use a common incremental expansion of the Company's current portfolio of natural gas transportation contracts. To ensure appropriate economies of scale are assigned to projects in this evaluation, the Company may allocate a prorated portion of costs from any plausible incremental expansion of its current portfolio of gas transportation contracts to these projects rather than the full cost of a specific pipeline or distribution system expansion.

Estimates for gas transportation charges are comprised of two components: 1) demand costs paid for pipeline capacity (i.e., buying space on the pipeline), and 2) variable costs which are charged on each MMBtu of gas delivered and consumed by the generation facility. The gas transportation charges include the costs for transporting gas on all of the pipelines required to deliver the gas from the Cheyenne Hub to the generation facility. The charges may include costs from Colorado Interstate Gas Company, Public Service, or any other pipelines that are required to deliver the gas to the generation facility pipeline interconnection point. If the generation resource has firm pipeline capacity that they expect to use as a part of their bid, the amount and costs of such capacity needs to be clearly indicated in the bid.

Gas Transportation Demand Costs

The Company currently has a portfolio of gas transportation contracts that provide firm gas supply along the Front Range of Colorado. Transportation capacity from these existing contracts not already allocated to generation facilities committed to serve Public Service loads will be made available to all proposed projects or portfolios through the current gas transportation contract termination date and up to the limits of the current gas transportation contract at no cost to the proposed generator. This may include making available any unallocated segments of a contracted gas transportation path that could be supplemented by new or incremental capacity to ensure a firm path of delivery from the Cheyenne Hub to any generation resource. The demand cost of these existing contracts are assumed to be sunk and therefore such costs will not be allocated to any portfolio of bids.

To the degree that additional firm gas supply above that available under current gas transportation contracts is needed, each portfolio will be assigned the appropriate level of additional transportation demand costs.

For generation projects that 1) do not directly interconnect with pipelines that have existing Public Service transportation contracts, 2) require gas volumes in excess of current Public Service contract availability levels, or 3) have proposed power purchase agreement terms that extend beyond the current Public Service gas transportation contract terms, additional transportation demand costs may be assigned to portfolios containing the bid. These additional costs may include the incremental costs associated with providing firm gas transportation access from the Cheyenne Hub or from the Company's existing portfolio of contracts based on maximum tariff rates or discounted rates for bypass options, the cost of extending current firm gas transportation contracts at existing rates, or at a rate necessary to recover the construction costs of acquiring firm gas transportation capacity. It is expected that the rates for service on each upstream pipeline, including Public Service, will be determined in accordance with the applicable tariffs as well as the applicable rate and facility policies of, and any necessary approvals by, the regulatory body that has rate and certificate jurisdiction over the upstream pipeline. To the extent a proposed project has sufficient on-site back-up fuel oil, the portfolios containing the proposed bid will not be allocated firm gas transportation charges beyond what is necessary to ensure a reliable primary fuel supply.

Gas Transportation Variable Costs

The variable transportation costs are comprised of the variable transportation charge, a Fuel, Lost and Unaccounted for (FL&U) factor (which is a percentage of the natural gas throughput that must be provided to the pipelines for operating their systems) and a balancing fee (unless the plant is directly connected to the CIG High Plains pipeline with access to the Totem Storage service) to account for hourly and daily imbalance swings on the pipelines. Gas transportation variable costs will include the firm gas transportation charges and the FL&U for all of the pipelines the gas flows through from the CIG Hub to the generation facility. The FL&U charge will be stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and will be at the price of gas commodity being delivered to the plant. A balancing fee of $0.0494 per MMBtu will also be added to all generation resources not directly connected to the CIG High Plains Pipeline system.

Incremental Gas Interconnection Costs

The projects that directly interconnect to those existing pipeline facilities for which the Company has existing transportation contract capacity will not be subject to additional interconnection costs above and beyond what is required in the original bid documents. For existing plants there will be no additional interconnection costs; for new plants, the Company requires bidders to identify the cost of connecting the plant to their proposed gas pipeline and include those costs in the bid package.

2.10 RESERVE MARGIN SUPPORT – LOLP STUDY

Public Service's 2008 planning reserve margin study, "Analysis of 'Loss of Load Probability (LOLP) at various Planning Reserve Margins," is provided in a separate document titled "Attachment 2.10-1_Planning Reserve Margin Study.pdf."

2.11 LOAD AND RESOURCE TABLE

Public Service's Load and Resource Table for the RAP is provided below as Attachment 2.11-1.

Attachment 2.11-1 RAP L&R

	A	B	C	D	E	F	G	H	I
1	**PSCo Loads & Resources Balance Summer 2011- 2022**								
2	**September 2011 Demand Forecast**								
3		**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
4	**Installed Net Dependable Capacity**	5,376	5,376	5,376	5,376	5,376	5,376	5,376	5,376
5									
6	**Planned Retirements**								
7	Arapahoe 3				-44	-44	-44	-44	-44
8	Cherokee 1		-107	-107	-107	-107	-107	-107	-107
9	Cherokee 2		-106	-106	-106	-106	-106	-106	-106
10	Cherokee 3						-152	-152	-152
11	Valmont 5								-184
12	Zuni 2					-65	-65	-65	-65
13									
14	**Planned Additions**								
15	Cherokee 2X1 CC						569	569	569
16	**Company Owned Subtotal**	**5,376**	**5,163**	**5,163**	**5,119**	**5,054**	**5,471**	**5,471**	**5,287**
17									
18	**Firm Purchased Capacity**								
19	Basin Electric Power Cooperative No.1	100	100	100	100	100			
20	Basin Electric Power Cooperative No.2	75	75	75	75	75			
21	Tri-State G&T No.2	100	100	100	100	100	100		
22	Tri-State G&T No.3	25	25	25	25	25			
23	Tri-State G&T No.5	100							
24	PacifiCorp (w/ reserves)	161	150	150	150	176	176	176	176
25	Wheeling Losses	(10)	(8)	(8)	(8)	(8)	(2)	0	0
26	**Thermal Non-Facility Specific Subtotal**	**551**	**442**	**442**	**442**	**468**	**274**	**176**	**176**
27									
28	ManChief Power Company	258	258	258	258	258	258	258	258
29	SWG Valmont 7 & 8	78	78						
30	SWG Arapahoe 5, 6, 7	121	121						
31	SWG Fountain Valley Midway	243	243						
32	Brush 1&3	78	78	78	78	78	78		
33	Brush 4D	133	133	133	133	133	133	133	133
34	Tri-State Limon	0	0	68	68	68			
35	Tri-State Brighton (Knudsen)	0	0	136	136	136			
36	Cogentrix Plains End	221	221	221	221	221	221	221	221
37	Thermo Fort Lupton	129	129	129	129	129	129	129	129
38	Thermo Power (UNC)	65	65	65					
39	Invenergy Spindle CT	284	284	284	284	284	284	284	284
40	Small QFs	38.8	37.1	34.6	34.0	33.9	33.9	33.8	23.7
41	WM Landfill Gas	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
42	**Thermal Facility Specific Subtotal**	**1,652**	**1,650**	**1,410**	**1,344**	**1,344**	**1,140**	**1,062**	**1,052**
43									
44	FPL Wind	50.1	50.1	50.1	50.1	50.1	50.1	50.1	50.1
45	Cedar Creek Wind	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6
46	Cedar Creek II Wind	31.3	31.3	31.3	31.3	31.3	31.3	31.3	31.3
47	Twin Buttes Wind	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
48	Colorado Green Wind	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
49	enXco Ridge Crest Wind	3.7	3.7	3.7	3.7	3.7	3.7		
50	Invenergy Spring Canyon Wind	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
51	Northern Colorado Wind I and II	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
52	Cedar Point Wind		31.5	31.5	31.5	31.5	31.5	31.5	31.5
53	Limon Wind			25.0	25.0	25.0	25.0	25.0	25.0
54	Limon II Wind (Approval Pending)			25.0	25.0	25.0	25.0	25.0	25.0
55	Ponnequin Wind	0.7	0.7						
56	Alstom NWTC	0.4	0.4	0.4	0.4	0.4			
57	Siemens NWTC	0.3	0.3	0.3	0.3	0.3			
58	NREL NWTC	0.5	0.5	0.5	0.5	0.5			
59	**Wind Subtotal**	**183**	**215**	**264**	**264**	**264**	**263**	**259**	**259**
60									
61	SunE Alamosa1	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
62	Greater Sandhills I	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
63	San Luis Solar		16.6	16.6	16.6	16.6	16.6	16.6	16.6
64	Cogentrix of Alamosa		16.6	16.6	16.6	16.6	16.6	16.6	16.6
65	Amonix SolarTAC 1	0.3	0.3	0.3	0.3	0.3			
66	On-Site PV (36 MW-Yr discounted)	31.0	44.9	58.4	71.4	83.7	95.3	106.8	118.3
67	**Solar Subtotal**	**44**	**92**	**105**	**118**	**130**	**142**	**153**	**165**
68									
69	**SPS Diversity Exchange**	**101**	**101**	**101**	**101**	**101**	**101**	**101**	**101**
70									
71	**PSCo Net Dependable Capacity**	**7,907**	**7,662**	**7,485**	**7,388**	**7,361**	**7,390**	**7,223**	**7,040**
72									
73	**PSCo Load**								
74	Sep 2011 Budget Forecast	**6,628**	**6,391**	**6,464**	**6,521**	**6,599**	**6,682**	**6,743**	**6,797**
75	Interruptible Load	**252**	**261**	**262**	**263**	**264**	**265**	**266**	**267**
76	Saver's Switch	**159**	**179**	**198**	**215**	**228**	**239**	**250**	**260**
77	Firm Sale PSCo-SPS 6/1/11 - 9/30/11	109							
78	**Firm Obligation Load**	**6,326**	**5,952**	**6,004**	**6,043**	**6,107**	**6,178**	**6,227**	**6,270**
79									
80	**Base Reserve Margin %**	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%	16.3%
81	Reserve Margin Requirement (MW)	1,031	970	979	985	995	1,007	1,015	1,022
82	IREA & HCEA Backup	40	40	40	40	40	40	40	40
83	Actual Reserve Capacity	1,581	1,710	1,481	1,345	1,254	1,212	996	770
84	**Resource Need MW (long)**	**(510)**	**(700)**	**(462)**	**(320)**	**(219)**	**(165)**	**59**	**292**
85		**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**

2.12 COAL PLANT CYCLING COST STUDY

The Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment for Public Service Company of Colorado study is provided in a separate document titled “Attachment 2.12-1_Wind Induced Coal Plant Cycling_Public.pdf.”

Consistent with Decision No. C11-0932, the Company submitted this study into Docket No. 11M-710E on September 6, 2011. Per the Decision, the Commission solicited stakeholder input regarding the study and asked interested parties to file comments on the study within 20 days of submission in the docket. As of October 28, 2011, no stakeholder comments have been submitted.

2.13 WIND INTEGRATION COST STUDY

Public Service's 2 GW and 3 GW Wind Integration Cost Study is provided in a separate document titled "Attachment 2.13-1_2G-3G Wind Integration Cost Study.pdf."

Consistent with Decision No. C11-0932, the Company submitted this study into Docket No. 11M-710E on September 6, 2011. Per the Decision, the Commission solicited stakeholder input regarding the study and asked interested parties to file comments on the study within 20 days of submission in the docket. As of October 28, 2011, no stakeholder comments have been submitted.

2.14 2011 WIND LIMIT STUDY

Public Service's 2011 Wind Limit Study is provided in a separate document titled "Attachment 2.14-1_2011 Wind Limit Study.pdf."

2.15 CHEROKEE 4 REPLACEMENT ALTERNATIVES STUDY

In Docket No. 10M-245E the Commission rendered its Final Order in Decision No. C10-1328 on December 15, 2010. Paragraph 135 of the Final Order required Public Service to "*…present alternatives to running Cherokee 4 on natural gas in its ERP fling due October 31, 2011…*" Potential alternatives suggested in paragraph 135 are "*New or reconfigured transmission resources, IPP-provided generation, and new alternative proposals for replacement generation at Cherokee Station …*" The Cherokee 4 Replacement Alternatives Study fulfills these directives.

Public Service's Cherokee 4 Replacement Alternatives Study is provided in a separate document titled "Attachment 2.15-1_Cherokee 4 Replacement Alternatives Study.pdf."

2.16 10-12 YEAR TRANSMISSION PLANNING STUDY

In Docket No. 10M-245E the Commission in Ordering Paragraph 27 of Decision No. C10-1328, December 15, 2010, required Public Service to "*develop a 10- to 12-year study of the Denver-Boulder load serving network, after soliciting input from Staff of the Commission regarding the scope of the study.*" The Commission directed Public Service to submit the study as part of its next ERP filing.

Public Service Transmission Planning initially met with the Commission staff on Dec 29, 2010. The goal of the first meeting was to gather input and information from Staff for preparation of the study plan for the 10-12 transmission study concerning the Denver–Boulder metro area. The parties discussed the scope of work with reference to Table 5 of Attachment TWG-1 of the rebuttal testimony of Tom Green (Docket No. 10M-245E).

On April 14, 2011, Transmission Planning again met with Staff and presented to them a draft scope of work. Input was received and the scope of work was finalized.

On September 30, 2011, Transmission Planning presented a draft report of the 10-12 year transmission study to Staff, discussed the content of the report and received input and comments on the report.

On October 6, 2011, the Company sent (via email) to the Staff the final draft of the report that had been modified based on the Staff's comments.

Public Service's 10-12 Year (Year 2022) Transmission Planning Study for the Denver-Boulder Area Load Serving Network is provided in a separate document titled "Attachment 2.16-1_10-12 Year Transmission Study.pdf."