Public Service Company of Colorado

2011 Electric Resource Plan

Volume I

(CPUC Docket No. 11A-   )

October 31, 2011

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1.1 EXECUTIVE SUMMARY

Public Service Company of Colorado's 2011 Electric Resource Plan ("2011 ERP") is a very different plan from that filed in 2007 because we face a very different set of conditions over the next five to ten years of this plan. The Company projects a relatively low incremental resource need, 292 MW, during the resource acquisition period (2011 through 2018), while at the same time expiring power purchase contracts will result in up to 1,200 MW of existing generation in the Colorado Front Range and in Wyoming being available to supply our requirements. The large amount of existing generation relative to our resource need should enable Public Service to obtain lower prices for new contracts. We have proposed a plan that provides competitive discipline to keep the prices offered from existing generation at a reasonable, low cost level.

The recent recession and current weak economy, together with the successful growth of our DSM and Solar Rewards programs, results in the Company projecting a need of just 292 MW of incremental generation capacity resources by 2018. By contrast, at the time of the CACJA filing in mid 2010, we were forecasting an additional resource need over this same period of approximately 1,000 MW. The Company's 2018 resource need has dropped by nearly 500 MW just since the beginning of 2011. In 2019 and beyond, the growth in capacity needs for Public Service's system is now forecast to be only in the 40 to 50 MW range per year. Based on growing national concerns about a possible second recession, there is uncertainty about our future sales and demand projections.

We also face uncertainty regarding future environmental regulations, changing technologies (e.g. declining cost of renewable technologies), tax credits that impact the relative cost of renewable generation and other alternatives, fuel prices, and economic growth in our service territory. In addition, the City of Boulder has placed on its November ballot the question of whether it should form a municipal electric utility. If this ballot issue passes and Boulder provides us notice they no longer anticipate taking service from us, our 2018 resource need would essentially be eliminated. These uncertainties together with the expectation that excess generation supply will exist in the region, suggest that it would be better to acquire resources for less than the maximum ten-year Resource Acquisition Period ("RAP") and to make shorter term resource acquisition decisions in this plan, and preserve decisions involving new generation facilities to a point in the future when we see how these uncertainties are resolved.

In addition, Public Service faces significant challenges over the next seven years implementing the resource plans already approved by the Commission. This 2011 ERP comes on the heels of the 2009 All-Source solicitation and the Company's plan to address the Clean Air-Clean Jobs Act ("CACJA"). The 2009 All-Source Solicitation will result in the installation of 700 MW of additional wind and two large 30 MW solar projects by the end of 2012. The Company has also recently requested approval of an additional 200 MW of wind resources to be on-line by the end of 2012. Under the approved CACJA plan, the Company has already retired Cherokee 2, a 106 MW coal unit to be converted to a synchronous condenser. The CACJA plan includes the retirement of 600 MW of centrally located base load coal generation, fuel switching at another 450 MW, and the addition of emissions controls on three other coal-fired units. These changes to the Public Service generation and transmission systems are of a magnitude never before experienced in Colorado. Successful implementation of these two plans is fundamental to maintaining the overall reliability and economic viability of the electric system in the State and we are fortunate to be able to implement these plans without the need for significant resource additions for load growth.

In the CACJA proceeding, the Commission ordered Public Service to reevaluate whether the continued operation of Arapahoe 4 and Cherokee 4 were needed for transmission reliability purposes. Our most recent transmission studies indicate that although generation resources in addition to the planned 2x1 combined cycle at Cherokee are beneficial to achieving desired transmission system performance, it appears that adequate transmission reliability can be achieved with the Cherokee 2X1 combined cycle facility and the Cherokee 2 synchronous condenser along with some transmission system reinforcements. A similar situation exists at Arapahoe. As a result, we are not proposing the construction of any more Public Service generation at Cherokee in this ERP. Further, these most recent transmission studies lead us to conclude that any must-run requirements on Arapahoe 4 and Cherokee 4 can be effectively eliminated, leaving Public Service with the beneficial and economical use of these two generation units operating as peaking plants after switching them from coal to natural gas. However, recognizing the amount of potential generation capacity in the region, it is possible that low cost proposals from other existing units could further reduce customer costs. This potential outcome will be considered when the Company assesses alternatives to the continued operation of Arapahoe 4 (109 MW) and our Cherokee 4 (352 MW) units on natural gas at the time of the Phase 2 bid evaluation process. The price protection for customers is that the Company can continue to operate Arapahoe 4 and Cherokee 4 on gas, as approved under the CACJA plan, if bids do not offer a lower cost alternative.

As a result of all these very unique factors, Public Service is proposing to focus our 2011 ERP on acquiring generation from existing facilities on a shorter-term contracting basis. We will focus our plan on minimizing costs for customers while preserving our ability to respond to changing circumstances. Public Service always strives to keep our rates to customers at a reasonable and low level; this is even more important as our customers continue to struggle to make ends meet in this weak economy.

Taking all of these issues into account, Public Service is proposing a resource plan that is targeting low-cost resources that will fill the resource needs through 2018, while also providing the flexibility to revaluate future market changes in the 2015 resource plan. The Company's proposed acquisition strategy is to ensure competition among existing generators for the anticipated 292 MW of resource need identified through 2018 and possibly to serve as alternatives to running Arapahoe 4 and/or Cherokee 4 on natural gas. Since these existing generators have already completed at least one-cycle of purchase power agreements with the Company and have had the opportunity to recoup a large portion of their capital investments in these plants, it seems logical that they would be in the position to offer Public Service much lower priced PPAs than a developer of new generation could offer. The Company will provide new self-build alternatives as a backstop plan to ensure the short-term acquisition strategy results in a lower cost to customers.

Finally, Public Service is well ahead of the Renewable Energy Standard ("RES") requirements for renewable energy. Due to the new wind and solar generation resources that are already installed or under contract coupled with banking of renewable energy credits ("RECs") and the Colorado in-state REC bonus, we expect to be in compliance with the Non-DG and Wholesale DG components of the RES through 2028. In addition, the Company is forecasting that the RESA deferred balance will not turn positive again until 2015. Given the state of our economy and the concerns expressed by our customers to keep rates as low as possible, Public Service is not recommending that the Company acquire any additional Non-DG or Wholesale DG renewable resources that would add incremental cost to the RESA before the negative RESA balance is eliminated. Public Service proposes, instead, that renewable energy resources compete head to head against non-renewable resources within the Phase 2 competitive solicitation process, without any renewable resource or Section 123 Resource set-asides. In addition, the Company proposes that it be allowed to pursue an "opportunistic" approach for acquiring additional renewable generation resources - an approach that provides the Company with the needed flexibility to acquire these resources when market conditions are most favorable for customers.

Summary of Major Plan Components and Proposed Action Plans

1) 2011 – 2018 RAP;
2) 292 MW of capacity need by 2018;
3) Assess alternatives to operation of Arapahoe 4 and Cherokee 4 on natural gas through 2025;
4) All-Source Solicitation will target short-term PPA with primary terms not extending past 2025;
5) No set-aside for Section 123 or 124 Resources;

6) Section 123 and 124 Resources will compete head-to-head against other resource options;

7) Public Service will, from time to time, use targeted solicitations to acquire additional renewable energy resources subject to Commission review and approval.

1.2 INTRODUCTION

Purpose of Filing

Public Service Company of Colorado ("Public Service") submits this 2011 Electric Resource Plan ("2011 ERP") pursuant to the Electric Resource Planning Rules, 4 CCR, 723-3-3600 *et seq* ("ERP Rules"). The 2011 ERP provides the framework for how the Company assesses the need for future electric supply resources over the specified 7-year Resource Acquisition Period ("RAP") of October 31, 2011 through October 31, 2018, as well as our plans for acquiring those resources.

The resource planning process in Colorado generally follows a two step process. The first portion, referred to herein as Phase 1, involves the utility ERP filing which includes information regarding the utility's electric system, an assessment of the need for additional resources as well as the utility's plan to acquire those resources. Through the Phase 1 proceedings the Commission establishes the need for new resources and the general methodology and assumptions the utility is to use in evaluating generation resources during the Phase 2 acquisition phase of the plan. It is within this Phase 2 acquisition phase that the utility implements the acquisition plan that the Commission approved in Phase 1. It is important to note that both the resource need determined in Phase 1 and some of the assumptions used for generation resource evaluation require updating before the evaluation of generation resource proposals takes place in Phase 2. These updates are performed using the methodologies approved in Phase 1.

The 2011 ERP also marks the first application of the Commission's new rules requiring utilities to provide an updated assessment concerning whether additional renewable resources are needed to comply with the Renewable Energy Standard ("RES") and whether eligible energy resources should be acquired as part of the ERP process. With this 2011 ERP, the Company concurrently filed its 2014 RES Compliance filing and seeks, in a corresponding motion, to consolidate the two filings.

The Company has an objective for the 2011 ERP beyond complying with the ERP Rules. The Company's objective, one shared by most stakeholders and the Commission is to reliably meet the needs of our customers at just and reasonable rates. The Company believes that the 2011 ERP meets that objective by structuring the needs assessment for both short-term and long-term periods in a manner that allows for more informed decisions, reduces the risk of long-term resource commitments and ensures a cost-effective result.

Changes to the Resource Planning Process

The Commission changed its ERP Rules in 2010 (CPUC Docket No. 10R-214E) and in 2011 (CPUC Docket No. 11R-416E). New ERP Rules require the 2011 ERP contain information on water resources (Section 2.4 of Volume II Technical Appendix) and provide a list of information that the Company will seek to protect as confidential or highly confidential (Section 1.9 below). The new ERP Rules also require an additional step in the resource acquisition process where the Company provides bidders who are advanced to portfolio modeling, information on how their bid will be represented in the evaluation process.

While the new ERP Rules resulting from Docket No. 11R-416E were not in effect when Public Service created and filed this 2011 ERP, Public Service used the ERP Rules as determined by Commission Decisions No. C11-0810 (July 13, 2011) and C11-0934 (August 29, 2011) to guide the construction of the 2011 ERP.

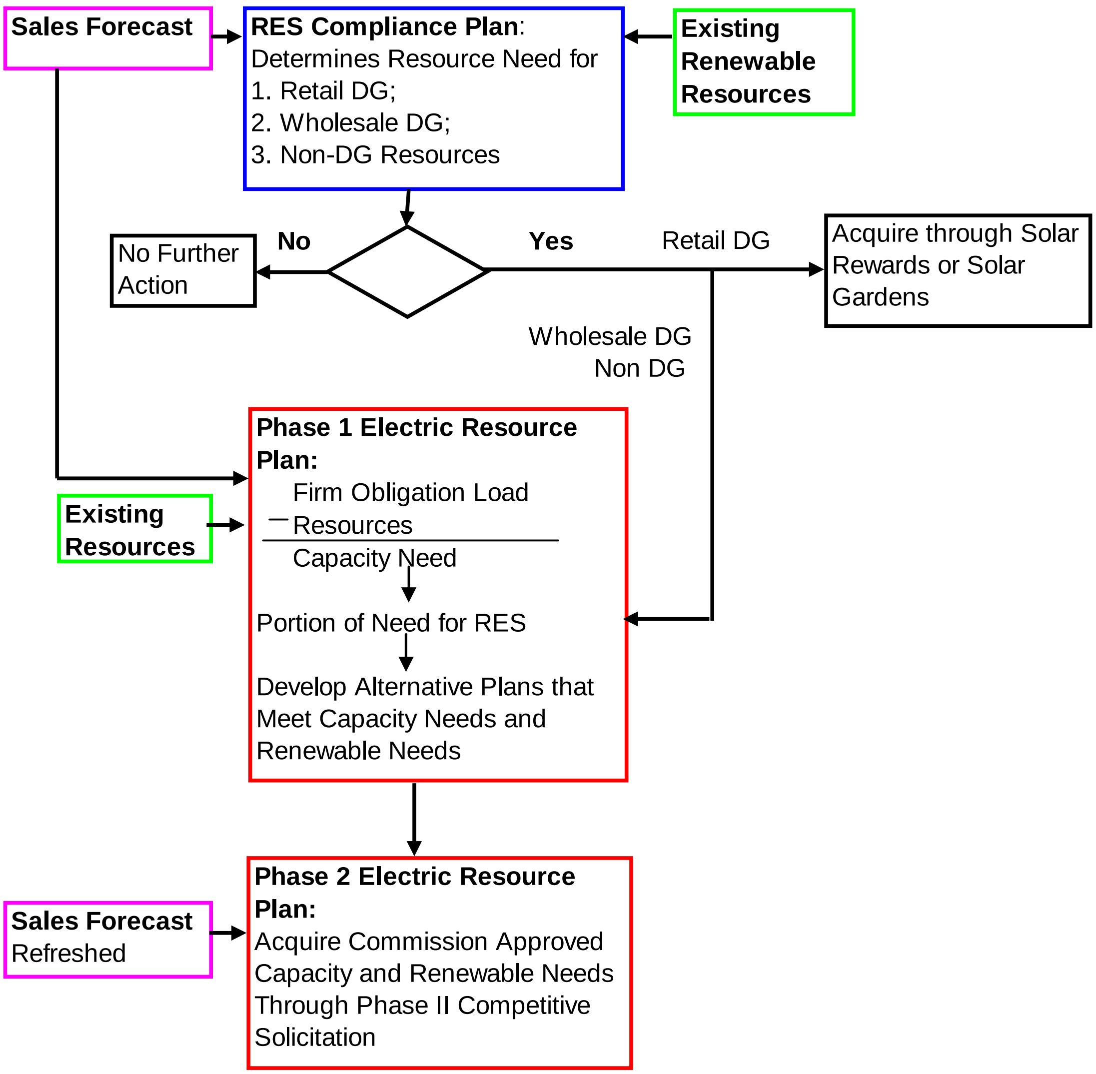
High Level 2011 ERP Process Overview

A high level overview of the ERP process, including how the RES compliance plan will inform the ERP assessment of need for additional resources and how that need is met with resources acquired in Phase 2, is illustrated in Figure 1.2-1.

Public Service's 2014 RES Compliance Plan, described later in this document, identifies that the Company does not need to acquire any additional Wholesale DG or Non-DG eligible energy resources in the RAP in order to comply with the RES.[1]

[1] Retail DG resources are acquired through the Company Solar*Rewards Programs

Figure 1.2-1 High Level 2011 ERP Process Overview



2007 ERP Amendment and the 2011 ERP

The Commission approved Public Service's 2007 Electric Resource Plan ("ERP") with certain modifications on September 19, 2008. The Commission with Decision C08-0929 ordered a set-aside for the acquisition of at least 200 MW of solar with storage facilities, with the caveat that the Company receives reasonable bids for the solar with storage resource. The Commission's Phase 2 decision issued on November 6, 2009, Decision No. C09-1257, approved Public Service's selected Portfolio No. 5, which contained a 250 MW concentrating solar with storage facility.

Portfolio No. 5 also included 105 MW of PV solar facilities that could be selected from a pool of PV solar bids.[2]

While in the process of implementing these Commission decisions, the Company determined that transmission construction timing and energy market conditions required amending the approved plan. As a result, Public Service filed Applications to amend its 2007 ERP on June 4, 2010 and again on November 19, 2010. The Company requested to amend the 2007 ERP to delay consideration of acquisition of the last 45 MW of solar PV and the 250 MW of solar thermal with storage resource until the 2011 ERP.[3] The Commission approved Public Service's proposed amendments and determined that it was "most beneficial to the public interest to defer a decision on the acquisition of a concentrating solar with storage resource to the 2011 ERP" and, concerning the PV solar resources, that the Company's request to "defer the acquisition of the remaining solar resources to the 2011 ERP…will be granted."[4] Consistent with these Commission determinations, Public Service developed alternate plans in this 2011 ERP that include consideration of both PV solar as well as concentrating solar with storage.

Contents and Organization of the 2011 ERP

This 2011 ERP filing is comprised of the following three volumes:

Volume 1: 2011 ERP

Volume 2: Technical Appendix

Volume 3: Requests for Proposals and Model Power Purchase Agreements

Volume 1 of the 2011 ERP contains the Company's assessment of need for additional resources and the Company's proposed plan for meeting that need.

Volume 2 provides detailed information about the Company's power supply resources and sales forecasts. Also included are descriptions of how the alternative plans were developed and analyzed, peer reviewed studies that address the costs of integrating intermittent resources on to our system, and Company transmission studies.

Volume 3 contains the requests for proposals and the model power purchase agreements that will be used to acquire generation resources.

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[2] Portfolio No. 5 also included 921 MW of gas-fired resources and 701 MW of wind resources.

[3] The Commission also approved Public Service's request to rebid the last 201 MW of wind resources targeted by the 2007 ERP. This led to a 200 MW PPA for the Limon I Wind facility.

[4] C11-0509, CPUC Docket No. 10A-377E, May 11, 2011, Paragraphs 58 and 60.

1.3 LANDSCAPE

Through our past Resource Planning efforts Public Service successfully developed a diverse and environmentally responsible portfolio of generation resources enabling the Company to provide our customers cost-effective energy. The Company's implementation of cost-effective demand-side management programs, expansion of our renewable energy portfolio and installation of emission control equipment at our existing generating plants have well positioned the Company to continue providing reliable cost-effective energy in the midst of the uncertainties the electric industry faces.

As we discussed in the Executive Summary, we are currently experiencing significant uncertainty regarding a host of issues that impact our business including the direction of the nation's economy and its impacts on future electric sales and the need for additional resources, the potential for future carbon legislation and the timing of such legislation, and the impacts that future accounting standards could have on our Company regarding power purchase agreements, to name a few. In addition the current circumstances include an overbuilt electric market in Colorado and an electric operations challenge to learn the best real-time operational practices while changing the generation portfolio greatly by adding 700-900 MW of intermittent resources and retiring over 600 MW of coal-fired units and permanently fuel switching another 450 MW. The centralized baseload coal-fired units that are fuel switching are either being replaced with high-efficiency natural gas generation or are continuing in operation but running on natural gas instead of coal.

This section discusses the areas of uncertainty that are expected to impact the Company over the 2012-2018 RAP. In addition the Company will discuss natural gas supply and price issues, the Company's RES compliance position, and our projections of carbon emissions reductions.

Uncertainty

Economic Recession and Reduced Forecasts of Electric Sales

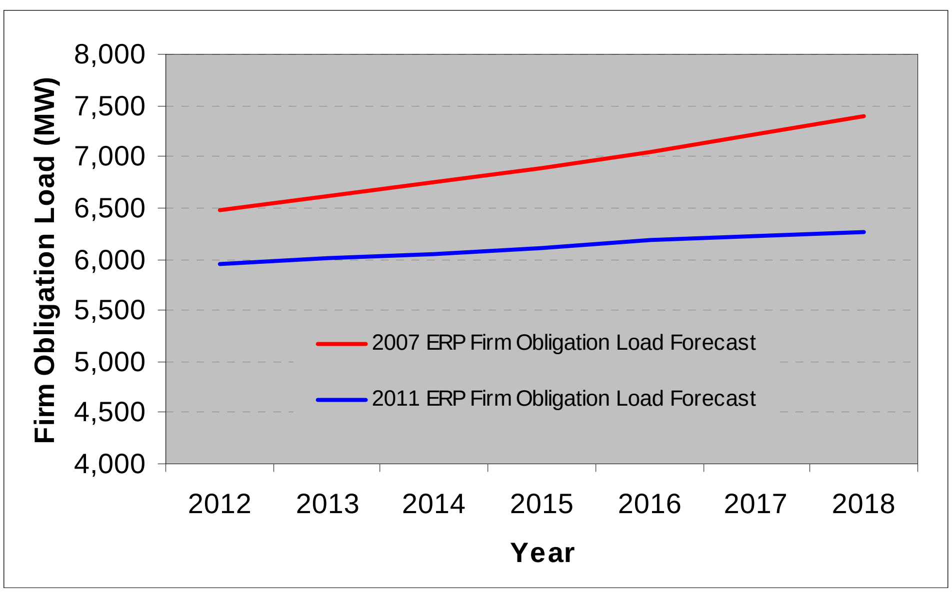
Colorado, the nation, and much of the world have experienced a severe recession since the Company filed the 2007 ERP. According to the U.S. Bureau of Labor Statistics, the number of jobs in Colorado peaked at 2,361,000 in April 2008 (the jobs peak). The State experienced job losses of 151 thousand or 6.4% by January 2010 (the jobs trough). Growth has been slow since then with just 30 thousand jobs recovered through August 2011. Unemployment rates moved up with these job losses from 4.0% in November of 2007 to 9.0% by early 2010. Unemployment remains high at 8.5% in August 2011.

Colorado's population grows through a combination of natural increase and net migration. Immigration to Colorado rises when the State's economy is growing and falls during hard economic times. Economic and population growth are important drivers for the demand for electricity in the State. The recession and slow recovery have dampened the current demand for electricity. Current economic conditions serve as a base for slower future growth based on slower long-term economic projections. As a result, forecasts are now calling for 255,000 fewer residents in the Colorado in 2018 as compared to what was expected at the time of the 2007 ERP. Similarly, while the number of jobs is forecast to increase, the total level of economic activity is now expected to be lower in 2018 than was forecasted in 2007.

Many recessions are short-lived with a steep downturn followed by robust growth. The recent economic decline has not followed this pattern. Instead, a very steep downturn has been followed by weak growth. This has been true for Colorado and the nation. As a result, forecasters are calling for long-term economic growth to shift downward and not rebound to the previous growth path. This can be seen by comparing the September 2011 Global Insight forecast to the same forecast from November 2007. U.S. Real Gross Domestic Product is forecast to be almost 9% lower in 2017 in the most recent Global Insight forecast as compared to the forecast completed in 2007.

Economy–related reductions in the forecast of electric demand combined with continued increases in DSM programs work in concert to produce a much lower forecast of the Company's firm obligation load than that produced for the 2007 ERP. Figure 1.3-1 contains a graphical comparison of the forecasts of firm obligation load for the 2007 ERP and this 2011 ERP.

Figure 1.3-1 Firm Obligation Load – 2007 ERP vs. 2011 ERP



City of Boulder Municipalization

The City of Boulder has placed, on its November ballot, the question of whether it should form a municipal electric utility. Current Boulder peak demand requirement is 243 MW. When grossed up for the Company's reserve margin, Public Service includes 287 MW of capacity to serve Boulder's electric needs. If this ballot issue passes and Boulder provides us notice they no longer anticipate taking service from us, the Company's 2018 need could be reduced to 5 MW.

Federal Environmental Regulation

Regional Haze, Ozone, Hazardous Air Pollutants

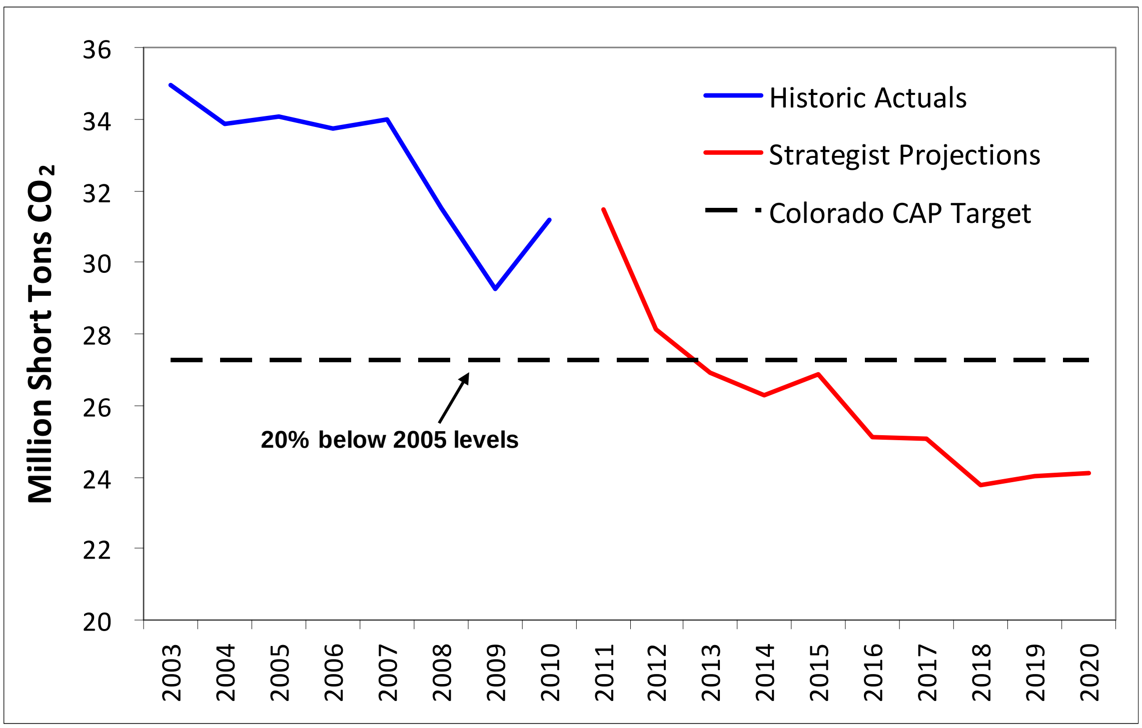
Public Service must comply with an array of federal environmental regulations that govern the construction of new generation resources and the operation of existing generation resources. These regulations include those pertaining to regional haze, ozone and hazardous air pollutants and they are discussed in more detail in Section 2.2 of Volume 2, Technical Appendix. As a result of the Company's past and ongoing actions involving the installation of emission controls in combination with the integrated plan of scheduled retirements, fuel switching and installation of additional emission controls pursuant to the Clean Air-Clean Jobs Act ("CACJA"), Public Service should be well-prepared to meet the requirements of Regional Haze, ozone non-attainment, and utility boiler hazardous air pollutant requirements for the foreseeable future without the need for additional emission controls.

Carbon Dioxide

Public Service is by most measures aggressive with integration of renewable energy onto our system and in the area of reducing emissions from our thermal generation resources. On October 9, 2011 in hour ending 4 AM, 56% of customer demand was met with wind generation – a new record on the Public Service System. For the full day on October 8th, 38% of customer demand was met with wind. By 2013, the Company expects to have over 2,100 MW of wind generation operating on our system, over 80 MW of utility scale solar PV, and over 130 MW of net-metered solar PV.

Our actions to improve Denver metro-area air quality through the early retirement of two coal units, Arapahoe 1 and 2, in 2003 set the stage for further emission reductions across other Xcel Energy electric operating companies. Early retirement of an additional 228 MW of coal-fired generation at Arapahoe and Cameo under the 2007 ERP built upon these earlier emissions reducing commitments. In 2010 in accord with the CACJA, the Company proposed and the Commission approved a plan to retire an additional 600 MW of coal-fired generation resources, fuel switch both Arapahoe 4 and Cherokee 4 from coal to natural gas and install emission controls on an additional 742 MW of coal units.[5] These CACJA retirement and fuel-switching actions alone are projected to reduce emissions of CO_2 by an amount equivalent to that resulting from the addition of approximately 1,400 MW of additional wind generation and over 300 MW of utility scale PV solar to the system. The overall effect of our continued DSM efforts and our completed and planned renewable energy additions and coal unit retirements is that by 2020, emissions of CO_2 from electric operations are projected to decrease by approximately 30% from 2005 levels, 10% more than the 20% reduction target established for year 2020 in the State of Colorado's November 2007 Climate Action Plan ("CAP").

Figure 1.3-2 CO_2 Projections and the Climate Action Plan



The state of carbon dioxide regulation remains in flux as the U.S. Congress and the Environmental Protection Agency ("EPA") consider how best to move forward. In a first step to regulate green house gas emissions (includes CO_2) EPA regulations now require, under the

[5] Represents Public Service's share of Hayden 1 & 2 and Pawnee 1.

Clean Air Act, that new and modified generation resources must seek a Prevention of Significant Deterioration air permit by following a process to demonstrate “Best Available Control Technology” for GHG emissions.. The Company is confident that any new generation facility that we propose to construct and own in this 2011 ERP will be granted the necessary permits for construction.

With regard to future regulation along the lines of a carbon tax or cap and trade approach, the November 2010 mid-term elections brought a shift in the balance of power in the U.S. Congress with the Republican party gaining control of the U.S. House of Representatives and additional seats in the U.S. Senate. Since that time, support for a climate bill has waned as increased attention has been focused on the economy, cuts in government spending and balancing the federal deficit. However, the EPA has stated its intention to propose and finalize rules regulating GHG emissions from major existing power plants in 2012. The EPA has not yet proposed these new rules. The political realities of delayed climate legislation, along with the uncertainties in EPA’s regulatory program have added increased uncertainty as to the form and timing of additional future federal carbon regulation. Nevertheless, the Company believes that the early action on our part over the past several years regarding the addition of cost-effective renewable energy to our system, combined with the retirement of aging coal units, has placed the Company in a good position to respond to any future federal regulation capping or limiting emission of carbon.

Tax Credits

The current production tax credit (“PTC”) and investment tax credit (“ITC”) for wind resources are set to expire December 31, 2012. It has been the Company’s experience that wind developers prefer to take advantage of the PTC as opposed to the ITC. The PTC produces a reduction in the price offered for a wind generation resource of in the range of $38/MWh for the ten year duration of the credit.[6] To date, all of the over 2,100 MW of existing or planning wind generation resources on the Public Service system have taken advantage of either the PTC or ITC thus helping reduce the cost that our customers pay for this renewable resource. While the PTC has seen several extensions in the past, the current climate in the U.S. Congress makes another extension uncertain.

[6] Approximately 2.2cents/kWh in 2011 escalated by an inflation assumption of 2% and divided by 1-composite tax rate of 38.01%.

The current 30% ITC for solar resources is set to expire December 31, 2016 at which time it will drop to 10%.[7] To date, all ~80 MW of existing or planned utility scale solar power on the Public Service system has qualified for the ITC thus helping to reduce the cost that our customers pay for this renewable resource.

<u>Accounting Standards</u>

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"). The accounting rules governing treatment of PPAs are currently in a state of flux as the country moves toward a new lease accounting standard with an effective date yet to be determined but estimated to be in the 2015 timeframe. The final leasing rules had yet to be issued at the time of filing this 2011 ERP, adding another layer of uncertainty that the Company faces in this planning process when it considers acquisition of additional power supplies through PPAs.

The terms and conditions of a PPA will determine whether Public Service is required to record the PPA on the Company books as a capital lease. Capitalization of lease assets and obligations, as required for capital leases, has negative impacts on the financial metrics of the Company. In addition, some credit rating agencies currently impute debt and interest expense for PPAs on the purchaser's (the Company's) financial statements for the purpose of determining credit ratings.

One aspect of a PPA that impacts the categorization of a lease under current accounting standards is the term or length of the agreement. In general, the shorter the term of the PPA, the less chance the contract will trigger the negative implications of a capital lease. This reality alone provides additional incentive for the Company to pursue shorter-term contract obligations in the 2011 ERP.

<u>Overbuilt Power Supply Market</u>

The economic downturn's effect of reducing forecasts of electric sales has contributed to the current excess generation capacity on the Public Service system and an expectation of continued excess generation capacity for the Colorado market and beyond for the next five or so years. As a result, the Company does not forecast a need for additional generation capacity until the summer of 2017. During the period 2013-2017 approximately 1,200 MW of existing power supply contracts between Public Service and other utilities and Independent Power Producers ("IPP"s) will expire. Approximately 800 MW of

[7] Developers can take 30% of a project's total development and construction cost as a tax credit.

those generation resources are peaking or capacity resources, the very type of resource shown to meet the resource need during the RAP in a least-cost manner in the analysis of "Alternative Plans" (see Section 1.5). Public Service expects that a significant portion of this 1,200 MW of power supply will be offered to Public Service to meet the need that begins in 2017.

The combination of capacity expansions (recently completed or under construction) and reduced demand owing to the economic downturn has led to an overbuilt situation in the Western Electricity Coordinating Council ("WECC"). NERC's 2010 Long Term Reliability Assessment projects the WECC region will remain in an overbuilt status through the assessment period ending in 2019 with reserve margins above 30% compared with a NERC target of just over 14%. More conservative estimates that assume less future capacity expansion still estimate regional reserve margins near 20% over the same period.

The level of uncertainty regarding various key industry-related issues discussed above, in combination with a projected surplus in generation capacity from existing facilities, presents a unique opportunity for the Company to fill some or all of our 2017-2018 capacity needs in the 2011 ERP using short-term commitments. The Company believes that in times of uncertainty, the ability to use short-term commitments to meet the resource needs of the 2011 ERP will bring additional value to our customers. This value comes in the form of the added flexibility afforded the Company in future ERPs to reassess which longer term alternatives make the most economic sense.. It is expected that when we file the 2015 and 2019 ERPs we will have additional clarity on a variety of the key issues affecting our business.

Short-term commitments would take one of two forms. For Company-owned facilities, the short-term commitment would be the continued operation of the existing Arapahoe 4 and Cherokee 4 facilities on gas until 2023 and 2028 respectively. For the facilities owned by IPPs or other utilities, short-term commitments would take the form of a short-term PPA, which would be defined as a contract that begins during the RAP and continues at least through the end of the RAP (October 2018), but does not continue beyond December 31, 2025.

Opportunities for short-term PPAs of this nature from existing generation facilities don't often present themselves within an ERP process. More often than not, projections of steady growth in firm obligation load throughout the RAP have produced resource needs that were best met with the construction of new generation facilities and/or long-term contracts. In such circumstances, regardless of whether the generation resource was offered by a utility or was IPP owned, a long-term commitment to purchase from the generation resource was required in order to finance its construction. Existing generation facilities that have already completed financing and construction should afford the facility owners the flexibility to entertain shorter term power sales to the Company.

Natural Gas

Market Price

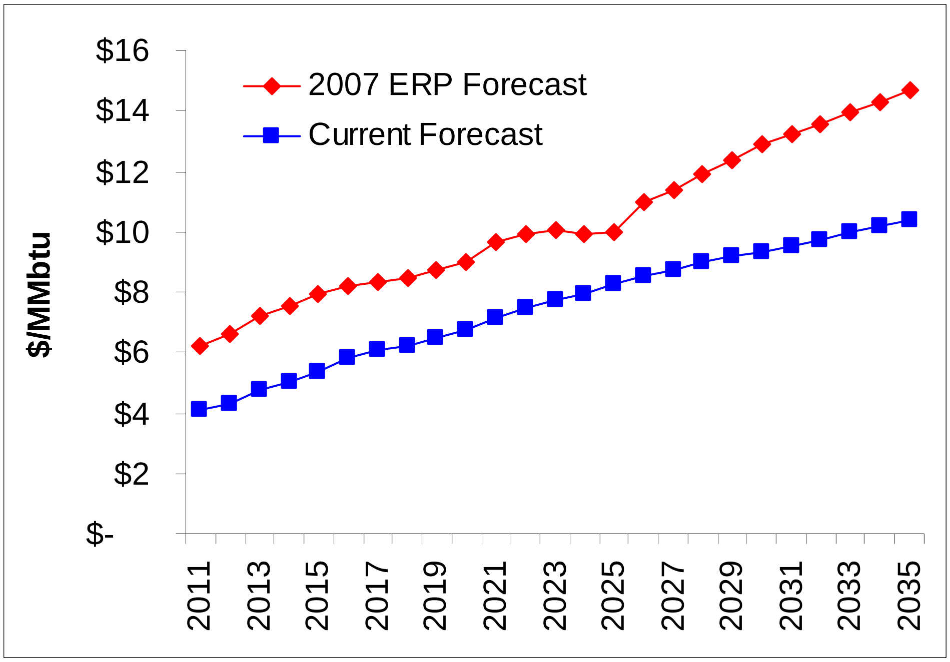
The market fundamentals for natural gas in the U.S. have changed dramatically over the past several years. The prevailing wisdom in prior outlooks was based on the premise that domestic production would continue to decline and a strong economy would support natural gas demand. This projected tightening of the supply/demand balance was forecast to drive prices higher. Projections also had the higher prices attracting liquefied natural gas to the U.S. away from Europe and Asia to meet demand. While unconventional domestic gas production – defined as production from shale, tight sands and coal bed methane – appeared to hold promise, production growth was projected to not be sufficient to keep pace with overall U.S. production decline rates.

The current situation looks much different. High natural gas prices in the last decade spurred a renaissance in natural gas drilling, which ultimately led to a reversal in domestic production declines by the 2007-08 timeframe. Unconventional natural gas resources were a large contributor. Shale gas production accounted for just 1% of domestic supply in 2000 but has grown to 20% of supply today. This explosive growth in shale production is largely due to two specific technology breakthroughs that have economically unlocked the potential of unconventional gas resources:

- Hydraulic Fracturing (“fracking”): high pressure injection of a mixture of water, chemicals and sand into a natural gas well to fracture the gas bearing rock and hold the fractures open with the sand to allow the natural gas to flow back to the wellhead.
- Horizontal Drilling: the drilling of a vertical well to reach the gas bearing layer of rock then extending the well laterally to reach a larger portion of the reservoir.

These technologies have been applied to an ever larger number of shale and tight sands formations in the U.S. from Texas (Barnett, Haynesville, Eagleford) to the Rocky Mountain region (Jonah, Pinedale, Piceance) and the Northeast U.S. (Marcellus) among others. Increased production and the nation’s economic climate lead to forecasts of gas price that demonstrate modest increases in price. See Figure 1.3-3.

Figure 1.3-3 Natural Gas Price Forecasts



The price of natural gas is a key driver in determining the cost-effectiveness of renewable resources such as wind and solar relative to gas-fired resources. Low gas prices make wind and solar less competitive with gas-fired resources while higher gas prices make them more competitive. While current forward projections show reduced price forecasts into the future, these are still forecasts and as such are not guaranteed to materialize. Factors that could alter the current price outlook include:

- Resistance to local drilling impacts (noise, air quality, land access, etc…)
- Water issues, including fears over contamination of ground water and fears of pollution associated with the disposal of "produced water" from fracking that could lead to greater regulation.
- Increased natural gas demand from faster-than-expected economic growth.

Longevity of Gas Supply

While the 2011 ERP alternate 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. Please see Section 2.2 of Volume 2, Technical Appendix for a detailed assessment.

Changes to our Electric Supply System

During the RAP, the Public Service generation resource portfolio will undergo two significant changes. First, the level of intermittent wind generation on the system will be increased by approximately 90% from approximately 1,200 MW today[8] to over 2,100 MW by the end of 2012. Second, the Company will be making wholesale changes to its Denver-metro area generation resources as a result of the CACJA passed into law in April 2010. The CACJA compliance plan specifies that, over the next 6 years, the Company will retire 600 MW of coal-fired generation resources, fuel switch two coal-fired resources to burn natural gas, and construct a new, high efficiency, combined cycle natural gas-fired generation resource.

Renewable Resource Additions

In accord with the 2007 ERP and associated processes, the Company will acquire approximately 1,075 MW of additional wind generation and 60 MW of additional solar PV, bringing the level of intermittent generation on our system to approximately 2,100 MW of wind and over 80 MW of utility scale solar PV by the end of 2012.[9] With these and prior renewable energy acquisitions, Public Service does not need to acquire any additional wholesale DG or non-DG resources in the 2011 ERP to meet the RES during the RAP. These 2007 ERP renewable resource acquisitions in combination with past renewable acquisitions have placed the Company well ahead of schedule in complying with the RES for wholesale DG and non-DG resources.

From a system operations perspective, the Company does not anticipate that this level of intermittent renewable generation will present significant challenges and/or problems to the continued reliable operation of the power supply system. Nevertheless, until such time that the Company gains actual operating experience with the level of intermittent generation that we have committed to acquire, Public Service plans to monitor several aspects of electric system operations (e.g., as described in the Company's 2011 Wind

[8] In recent months test energy from an additional 500 MW of wind has been added to system. However, Company operators have little if any experience operating the system with 1,700 MW of wind on a continual basis.

[9] Wind = 175 MW NOCO I and II wind + 700 MW wind from 2007 ERP + 200 MW Limon II wind
Solar = 7 MW SunE Alamosa + 18 MW Greater Sandhills + 60 MW 2007 ERP PV

Limits Study[10], and as described in Section 2.9 as it pertains to intermittent PV generation).

CACJA

As the Company learns to operate its system with substantially increased levels of intermittent wind and solar resources, we will also be making wholesale changes to the Denver-Boulder area dispatchable generation resources in accord with the approved CACJA compliance plan. The CACJA compliance plan specifies that, over the next 6-years, the Company will: 1) retire 600 MW of coal-fired generation resources, 2) fuel switch two coal-fired resources to burn natural gas, 3) construct a new, high efficiency, combined cycle natural gas-fired generation resource, and 4) install emission controls on three existing coal-fired generation units.

As with the operational concerns posed by the addition of intermittent generation resources, the Company does not anticipate that these CACJA changes will present significant challenges and/or problems to the continued reliable operation of the power supply and electric transmission systems; but we will not know for certain until such time as we have gained some level of operational experience with the altered system.

Since mid-2010 when Public Service was evaluating options to comply with CACJA, the Company has continued to investigate the transmission reliability issues associated with the retirement of Cherokee 4. The Company's transmission reliability investigation has determined that it is preferable, but not necessary, to site a portion of the replacement generation for the retirement of Cherokee 4 at the Cherokee site.

Conclusions

The current industrial, economic, and political environment is in stark contrast to the environment that the Company faced when we filed the 2007 ERP. At that time economic indicators suggested the Company would see an average of 2.4% annual peak load growth, the U.S. Congress was actively considering carbon legislation with a proposed bill getting so far as passing in the U.S. House of Representatives, Governor Bill Ritter had recently adopted a Climate Action Plan seeking 20% reductions in CO_2 by 2020, gas price forecasts predicted high gas price escalation, and PTCs for wind had been extended. Considering our current assessment of the landscape for this 2011 ERP, the Company's RES compliance position, and our position concerning the State's Climate Action Plan, Public Service finds itself in a position to adopt a least-cost focus for the 2011 ERP with the added value of having the opportunity to rely upon short-term commitments to meet all or a portion of the

[10] See Section 2.14, Volume2 in the Technical Appendix.

resource need. Consequently, the Company proposes that the 2011 ERP establish no "set aside" or "target" for renewable resources or Section 123 Resources for any portion of the resource need, but rather establish an "opportunistic" approach for acquiring these generation resources - an approach that provides the Company with the needed flexibility to acquire these resources when market conditions are most favorable for customers. With regard to non-renewable or non-Section 123 Resources, the Company proposes that the 2011 ERP not "set aside" or "target" any portion of the resource need for new Company-owned projects, but rather recommends that all new projects -- Company-owned or IPP-owned -- be put forward for consideration into a Phase 2 competitive solicitation process. Within that competitive process the Company plans to put forward low-cost, brown-field expansions of existing Company-owned generating facilities. These low-cost Company proposals should serve to discipline the competitive process and ensure that the winning portfolio, whether comprised of all Company-owned proposals, all IPP-owned bids, or some combination of the two, produces the most cost-effective generation resource portfolio as the result of competitive market forces working in the best interest of our customers.

Resource Acquisition Period (RAP)

The Resource Acquisition Period or RAP is the period in which the utility works to acquire generation resources to meet the electric system resource need projected in the ERP. The Commission's resource planning rules allow jurisdictional utilities the option of selecting a RAP of between six to ten years from the date the plan is filed. For the 2011 ERP, Public Service specifies a seven-year RAP that will run from October 31, 2011 through October 31, 2018, thereby addressing the summer peak needs of our systems for years 2012 through 2018.

Given the uncertainty associated with various key economic and industry issues discussed above, the Company believes it is not prudent or necessary to commit to additional power supply resources in this ERP too far into the future. The Company's assessment of resource need shows no need until the summer of 2017 and our analysis of "Alternative Plans" indicates that the most cost-effective resource additions for the system at that time are expected to be gas-fired peaking resources. Gas-fired resources (both simple cycle combustion turbines and combined cycle combustion turbines) and most renewable resource technologies generally require development and construction lead times from one to four years. Therefore, a seven-year RAP should not limit the ability of parties to propose new generation resources that could meet a 2018 need in a solicitation associated with the 2011 ERP.

In assessing the appropriate RAP for this 2011 ERP, the Company also considered how the 2011 ERP's RAP might impact the ability to consider generation resource options in the 2015 ERP.[11] For example, if a six year RAP were selected for the 2011 ERP (Oct 2011- Oct 2017) the summer of 2018 would represent the first year outside the RAP in which any resource need not filled in the 2011 ERP might occur. In that situation new generation resources selected in the 2015 ERP would require an overly aggressive and compressed construction schedule in order to be available for the summer of 2018. By contrast, election of a seven year RAP in this 2011 ERP, 2012-2018 would provide an additional year to develop projects selected in the 2015 ERP.

The selection of a seven-year RAP will allow Public Service to consider an adequate range of resource technologies in this 2011 ERP and acquire the resources we need to reliably meet our customer needs through 2018 in an orderly manner. It is anticipated that the conclusion of the first phase of the new resource plan process will position Public Service to begin the acquisition of new resources (primarily for the years of 2017 through 2018) with sufficient time for new resources to be constructed in a timely manner.

Planning Period

The ERP Rules prescribe a Planning Period between twenty to forty years. Public Service proposes to use a 40-year Planning Period in the 2011 ERP that extends to the year 2050.

[11] The RP Rules requires utilities to file an electric resource plans every four years.

1.4 RESOURCE NEED ASSESSMENT

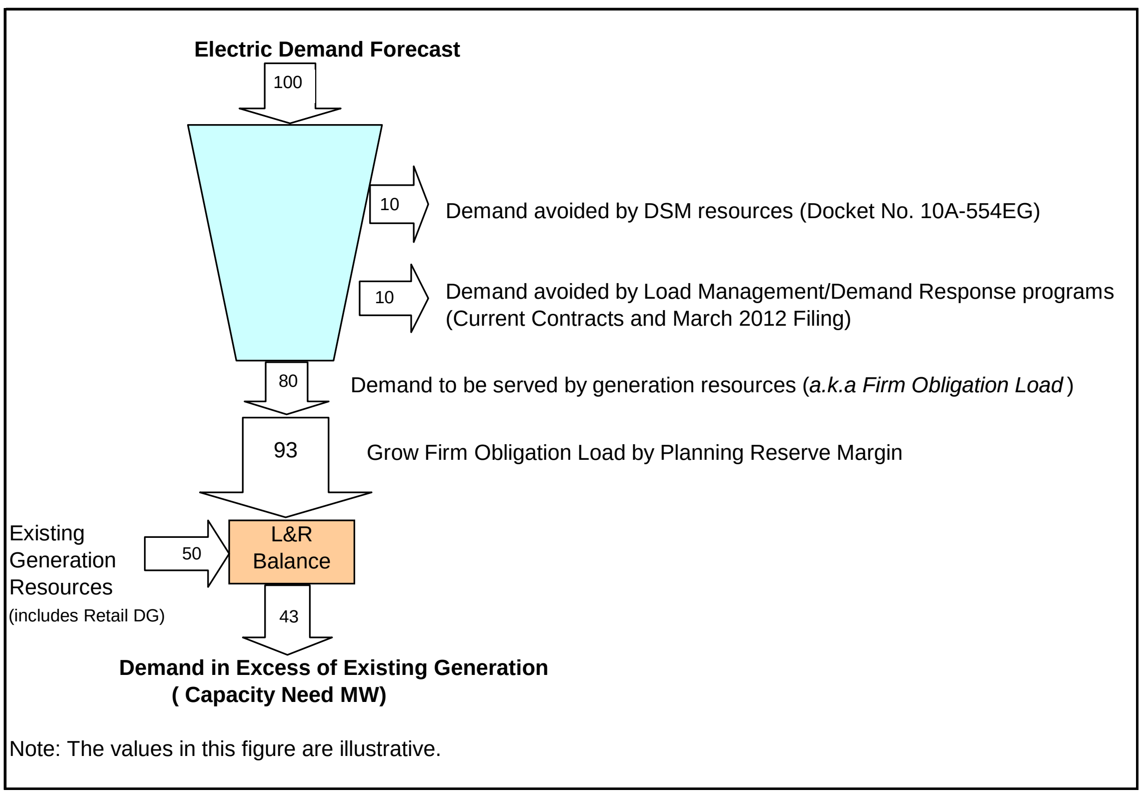
For this 2011 ERP the assessment of need for additional resources focused on three areas of potential need:

1. generation capacity to meet reserve margins
2. renewable energy to meet the RES
3. “flexible” generation resources for integrating renewable resources

Generation Capacity Assessment

By comparing the electric demand forecasts with the existing level of generation resources and planning reserve margins over the RAP, the Company determines whether there is a need for additional generation capacity on our system. This assessment is commonly referred to as a “load and resource balance.” The assessment accounts for the reduction in peak demand resulting from the Company’s DSM programs and demand response programs. Also captured in this assessment is the estimate of generation from retail DG resources over the RAP as a result of the Company’s Solar*Rewards Programs. Figure 1.4-1 provides a diagram of the main components considered in the capacity need assessment.

Figure 1.4-1 Capacity Need Assessment



The need for additional generation capacity is heavily influenced by the forecasts of peak demand. Public Service's electric energy and demand forecast anticipates relatively low growth through the RAP. As discussed in Section 1.3, Colorado has not been immune to the economic recession occurring in the nation. The Company's forecast of firm obligation load exhibits the influence of low economic expansion expectations. The electric firm load obligation forecast that Public Service last provided the Commission did not show strong growth but was nonetheless more optimistic as to the economy's ability to pull out of the current recession. Table 1.4-1 contrasts the April 2010 and September 2011 forecasts of firm obligation load at the time of the system peak which for Public Service typically occurs in late July.

Table 1.4-1 2010 and 2011 Forecasts of Firm Obligation Load (MW)

Firm Obligation Load	2012	2013	2014	2015	2016	2017	2018
2010 Forecast	5,926	6,048	6,172	6,288	6,409	6,549	6,644
2011 Forecast	5,952	6,004	6,043	6,107	6,178	6,227	6,270

The firm obligation load figures in Table1.4-1 include the forecasted contribution from the Company's energy efficiency initiatives, Savers Switch, the Interruptible Service Option Credit and Third Party Demand Response programs (see Section 2.4 of Volume 2, Technical Appendix) that all reduce obligation load. Public Service included the City of Boulder's entire firm load obligation for both the RAP and the Planning Period. In the event the City of Boulder decides to form an electric municipal utility and gives notice to the Company that Boulder no longer wishes to take service from us, the Company will remove the city's load from its forecast of firm obligation load and thereby not acquire additional resources in this ERP needed to continue serving the city.

Table 1.4-2 summarizes the Company's current assessment of the need for additional generation capacity.

Table 1.4-2 Summary Capacity Need Assessment (MW)

Row		2012	2013	2014	2015	2016	2017	2018
A	Existing Generation	7,662	7,485	7,388	7,361	7,390	7,223	7,040
B	Firm Obligation Load	5,952	6,004	6,043	6,107	6,178	6,227	6,270
C	Planning Reserve Margin	1,010	1,019	1,025	1,035	1,047	1,055	1,062
(B+C)-A	**Capacity Need**	**(700)**	**(462)**	**(320)**	**(219)**	**(165)**	**59**	**292**

Note: Resource Need Row is from Actual L&R and differs from the sum of rows B and C minus row A due to number rounding in 2013.

Negative values in Table 1.4-2 indicate years in which surplus generation capacity is expected to exist. Positive values indicate years in which additional generation capacity is needed in order to meet a 16.3% planning reserve margin. Note that projections of Retail DG resources attributable to the Solar*Rewards Programs are taken into account within the Company's existing generation resource total. The detailed load and resource balance used to produce Table 1.4-1 is included in Section 2.11 of the Technical Appendix.

Public Service proposes that this capacity need assessment be updated with the then current load and resource information just prior to the Phase 2 competitive solicitation process to determine the capacity need for the acquisition of additional resources.

Renewable Energy Assessment

Public Service's 2014 RES Compliance Plan describes that Public Service does not need to acquire any additional Wholesale DG or Non-DG eligible energy resources in the RAP in order to comply with the RES both during the RAP and for many years beyond the RAP. Figures 1.4-2 and 1.4-3 illustrate our compliance position by comparing the Company's estimated REC balance with the RES requirements. For purposes of these illustrations, the RES is presented in two categories, wholesale DG, and non-DG.

Figure 1.4-2 Wholesale DG Compliance Forecast

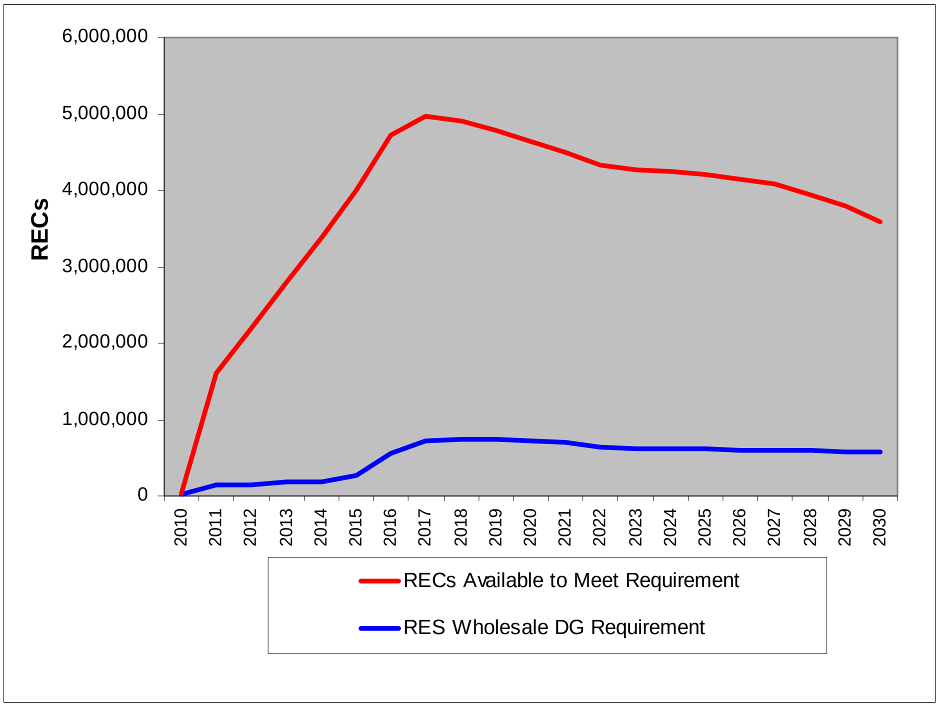
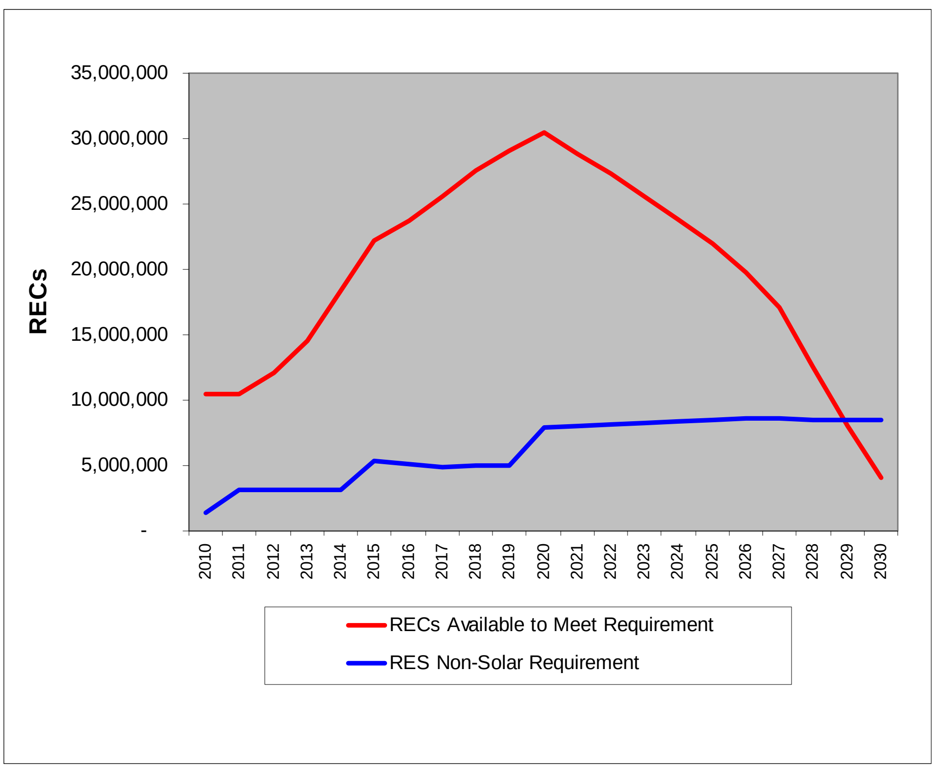


Figure 1.4-3 Non-DG Compliance Forecast



Given there is no need for additional Wholesale DG or Non-DG eligible energy resources, the Company proposes no set-aside nor target for additional renewable resource capacity for purposes of complying with the RES during the Phase 2 competitive acquisition process.

Flexible Resource Assessment

Public Service plans to have over 2,100 MW of wind generation operating on its system by the end of 2012. The variability and uncertainty of wind generation places additional requirements for generation that can be brought on-line within a 30-minute timeframe to help maintain the balance between generation and load. Public Service refers to resources that meet this 30-minute guideline as “flexible” resources. Part of the Company’s assessment of need for this 2011 ERP involved an assessment of the level of flexible resources that would be available on the Public Service system throughout the RAP. The intent of this assessment was to determine whether sufficient 30-minute capable generation supplies will exist throughout the RAP to cover the over 2,100 MW of wind generation that is expected by the end of 2012, or whether additional resources were needed. To the extent additional 30-minute capable generation were needed, such resources could either be pursued in the ERP or, in certain instances, be obtained by changing the performance of existing generation resources, e.g., obtaining firm gas supply for a generation resource or making equipment changes that allow quicker generation resource start.

In performing this assessment power supplies from PPA’s were only counted as contributing to the pool of 30-minute resources during the years covered in their current PPA term. These PPA’s were not included in the assessment for years after the PPA termination date. In addition, the level of 30-minute capable resources was reduced to reflect that spinning reserves are not considered as part of the 30-minute pool of resources available to manage wind ramp-downs. The results of this assessment show that Public Service will have a surplus of flexible generation resources in every year of the RAP.

1.5 LEAST-COST BASELINE CASE AND ALTERNATIVE PLANS

Section Overview

RP Rule 3604(k) requires utility resource plans to provide descriptions of a baseline case and alternate plans that can be used to estimate the costs and benefits of increasing amounts of renewable energy resources, demand-side resources, or Section 123 Resources that could potentially be part of a cost-effective resource plan. Public Service developed plans that meet this requirement using generic cost and performance estimates for a variety of generation technologies that are likely to be available to the Company for use in filling its projected resource needs.

Public Service developed a "least-cost baseline case" which is a plan that meets the resource needs during the RAP at the lowest cost as measured by net present value of revenue requirements ("PVRR"). In addition to this least-cost baseline case, Public Service developed eight "alternative plans" that meet the same resource needs using increasing amounts of renewable energy resources and Section 123 Resources. All plans contained sufficient renewable energy to meet the Renewable Energy Standard, 4 CCR 723-3-3650 et seq., and contained a level of DSM resources that the Commission established in CPUC Docket No. 10A-554EG in compliance with the requirements of CRS 40-3.2-104.

The least-cost baseline case and alternative plans were modeled within a Strategist computer model representation of the Public Service electric system for years 2011-2050. Strategist was then used to estimate the PVRR of each plan under a range of futures.

Resource Technologies Considered

There are a variety of generation technologies available to Public Service for use in meeting our need for additional power supplies. Tables 1.5-1 and 1.5-2 summarize those technologies used in constructing the least-cost baseline case and alternative plans. Public Service considered the battery and solar thermal technologies to be Section 123 Resources for purposes of developing the least-cost baseline case and alternative plans. The practical result of the Section 123 designation is that the incremental costs of these resources do not count towards the 2% retail rate impact limitation of the RES.

Table 1.5-1 Generic Dispatchable Resource Cost and Performance

Dispatchable Resources [1,2]	2x1 Combined Cycle	1x1 Combined Cycle	Combustion Turbine	Battery
Nameplate Capacity (MW)	808	346	214	25
Summer Peak Capacity with ducts (MW)	658	315	173	25
Capital Cost ($/kW)	$661	$1,040	$566	$3,000
Fixed O&M Cost ($000/yr)	$4,662	$3,414	$661	$0
Variable O&M Cost ($/MWh)	$2.37	$2.43	$10.43	$0.00
Ongoing Capital Expenditures ($000/yr)	$3,386	$1,903	$1,343	$0
Heat Rate 100 % Loading (btu/kWh)	6,947	6,733	10,596	N/A
Typical Capacity Factor	37%	37%	9%	N/A

Notes:

(1) All costs in year 2011 dollars unless noted

(2) Costs for the 2x1 and 1x1 combined cycle and combustion turbine represent an average of greenfield and brownfield estimates of Siemens 5000F facilities. These average costs are used to represent resources available during the RAP. Resources added past the RAP assume greenfield facilities. Table 2.8-1 in the technical appendix includes more detailed information about each generic resource.

Table 1.5-2 Generic Renewable Resource Cost and Performance

Renewable Resources [1,2]	Non PTC Wind	30% ITC Solar PV	10% ITC Solar Thermal with storage	10% ITC Solar Thermal with storage
Nameplate Capacity (MW)	100	25	50	125
ELCC Capacity Credit (MW)	12.5	13.8	50	125
Variable Cost ($/MWh)	$68	$99	$253	$223
Dispatchable	no	no	partial	partial
Typical Capacity Factor	48%	30%	38%	38%

Notes:

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

(2) See Table 2.8-2 for a more detailed list of assumptions.

These estimates are termed “generic resources” because while they include all major cost and performance characteristics of each technology for a Colorado elevation, they do not reflect a specific site location. It should be noted that the capital costs used to represent gas-fired combined cycle and combustion turbine technologies in Table 1.5-1 are reflective of the midpoint of a cost range for these facilities depending on whether they are developed as “Greenfield” facilities under an Engineering, Procurement and Construction (“EPC”) approach or as “brownfield” expansions on existing Company generation sites under a Company managed approach. The lower end of the capital cost range for the generic 2x1 and 1x1 combined cycle facilities are $609/kW and $899/kW respectively while the upper end of the capital cost range for the generic 2x1 and 1x1 combined cycle facilities are

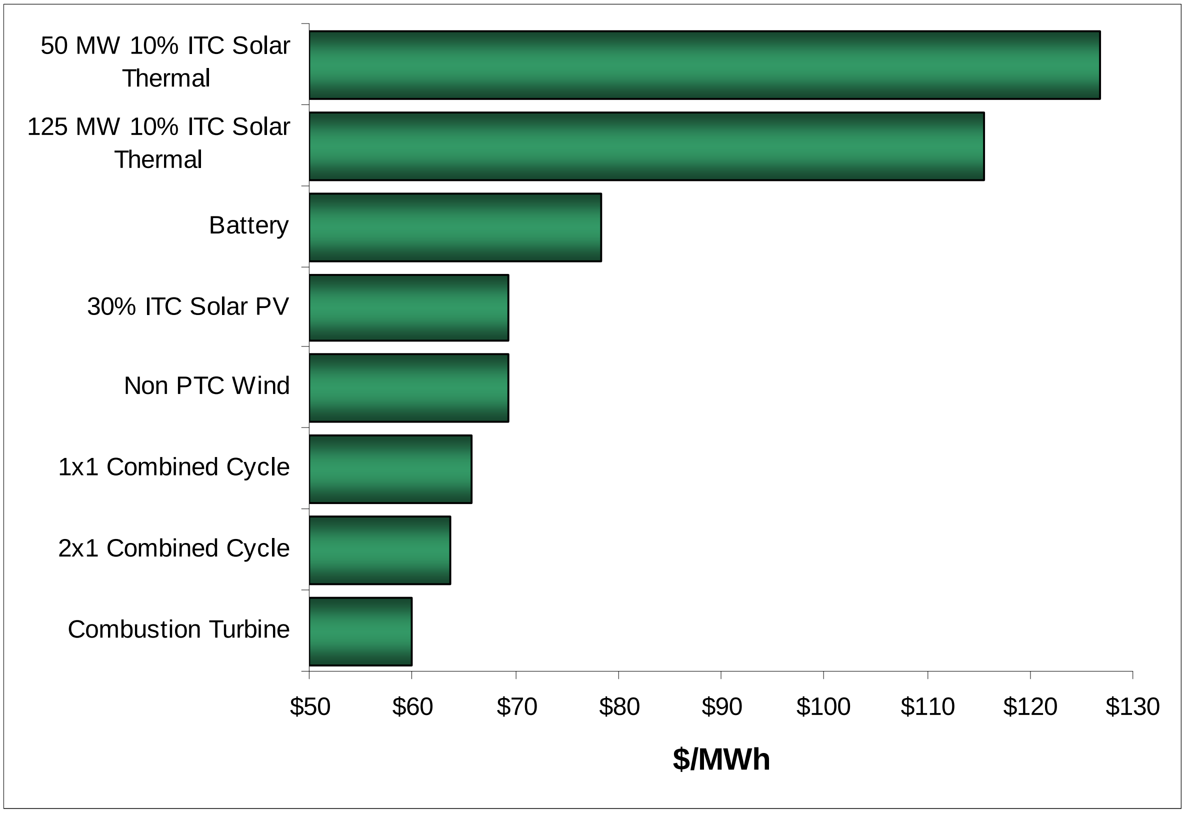
$713/kW and $1,181/kW respectively. The lower and upper ends of the capital cost range for the generic combustion turbine facility are $477/kW and $655/kW respectively.

We emphasize that this generic resource cost and performance information contains representative estimates for these technologies for purposes of developing the least-cost baseline case and alternative plans. Actual bids received in response to a competitive solicitation process may propose different technologies with different performance and pricing than that used to represent these generic resource estimates. Additional details about these estimates are provided in Section 2.8 of Volume 2, Technical Appendix.

Technology Cost Comparison

A common methodology used to represent the cost of producing electric energy from different generation technologies is levelized energy cost ("LEC"). Public Service uses the LEC metric as part of its bid evaluation processes. But differences in how and when various technologies produce energy limit the usefulness of LEC values when comparing the cost-effectiveness of one generation technology versus another. By accounting for these differences within the calculation of LEC, however, one can develop LEC values that provide a reasonable representation of how each technology would help serve both the capacity and energy needs of an electric system, resulting in LEC values for the different technologies that are more comparable with one another. Figure 1.5-1 shows LEC values for the generic resources in Tables 1.5-1 and 1.5-2 that are considered in the RAP and account for the differences between technologies by placing each LEC on an equivalent basis with regard to 1) the amount of energy included in the LEC calculation and 2) the amount of firm generation capacity included in the LEC calculation. Details on these calculations are provided in Attachment 2.8-4 of Volume 2, Technical Appendix.

Figure 1.5-1 Technology LEC Chart

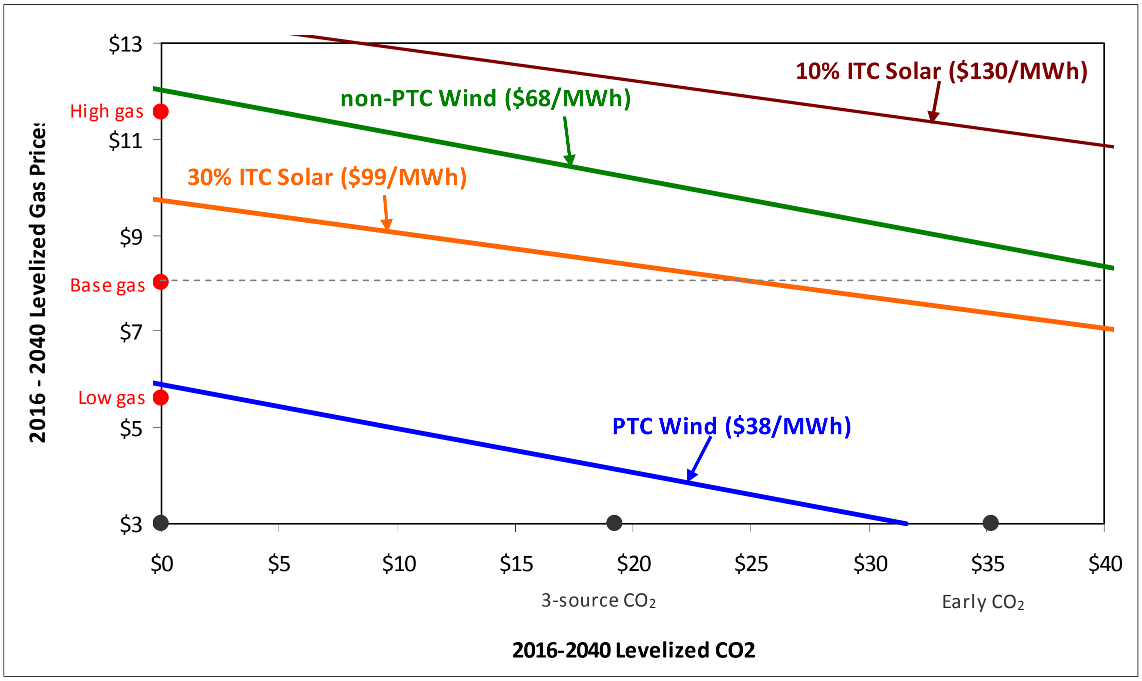


Cost-Effectiveness of Additional Renewable Resources

Several factors impact the cost-effectiveness of adding more renewable generation resources, such as wind and solar, to the Public Service system including, the capital cost to construct the facilities, the level of wind and solar already on the system, the availability of tax incentives, costs assigned to emissions of CO_2, the price of natural gas, and the cost to acquire gas-fired generation resources (either through construction or contracting with existing facilities). However two of these factors, the price of natural gas and the cost assumed for emissions of CO_2 are perhaps most influential in the cost-effectiveness equation. To provide the Commission with additional insight as to how these two variables can influence the cost-effectiveness of renewable technologies, Public Service estimated the cost impacts of adding renewables to our system at various gas and CO_2 pricing levels, using the generic resource cost estimates. Figure 1.5-2 summarizes the results of this analysis showing the gas and CO_2 levels when wind and solar PV start to become economical. This figure indicates, for example, that at the base gas forecast and at $0/ton CO_2, PTC wind appears economical as the PTC wind breakeven line is below the 2016-2040 levelized base gas forecast price of $8.01/MMbtu at $0/ton CO_2. In contrast, non-PTC wind is not economical at base gas prices as the non-PTC wind breakeven line is above the base gas forecast levelized price at $0/ton

CO_2. For non-PTC wind to be economical at the base gas forecast, it would need to have a levelized 2016-2040 CO_2 price of above approximately $40/ton.

Figure 1.5-2 Cost Effective Resource Curve



Development of Least-Cost Baseline Case and Alternative Plans

Both the least-cost baseline case and alternatives plans were developed using the Strategist computer model in a manner consistent with that used by the Company and approved by the Commission in CPUC Dockets 07A-447E and 10M-245E. To provide the costs and benefits of increasing levels of renewable and Section 123 Resources over the Planning Period as required by RP Rule 3604(k), it is necessary to use a computer model such as Strategist when developing these plans, rather than rely simply on the LEC analyses. The basic modeling framework consists of a series of steps that are summarized below. A more in-depth discussion of this process is contained in Section 2.8 of Volume 2, Technical Appendix.

Construct Base Model

A representation of the Public Service electric supply system is constructed that reflects the Company's existing generation mix (both owned and purchased) as well as planned, but yet to be completed, generation resource actions resulting from the 2007 ERP and CACJA.[12] The model also includes the 200 MW Limon II wind facility currently before the Commission for

[12] Including fuel switching Arapahoe 4 and Cherokee 4 starting January 2014 and January 2018, respectively.

approval. Embedded within this long-term sales forecast are demand and energy savings consistent with a level of DSM resources that the Commission established in CPUC Docket No. 10A-554EG. Additional retail-DG, wholesale DG, and non-DG renewable resources are included to comply with the RES throughout the entire 2011-2050 Planning Period. This base model utilized what are referred to herein as “starting assumptions”[13] to represent key system characteristics such as fuel pricing, sales forecasts, inflation rates, etc.

The resulting model representation showed a need for additional generation capacity within the RAP of approximately 60 MW in 2017 and 300 MW in 2018 in order to meet a 16.3% planning reserve margin. The base model also has a need for additional generation capacity to meet a 16.3% planning reserve margin for all future years beyond the RAP. This need arises from not only load growth but also assumed retirements of existing company owned resources and PPA expirations.

Develop Least-Cost Baseline Case

Starting with the base model described above, a series of Strategist optimization runs were performed in which the model was allowed to fill both the RAP capacity needs and the future year needs beyond the RAP from the generic resources described in Tables 1.5-1 and 1.5-2.[14] From these optimization runs Public Service was able to ascertain which of the generic resource technologies met the RAP needs as well as the future year needs in a least cost manner.

Develop Alternative Plans

The resulting least-cost baseline case formed the foundation upon which alternative plans that include increasing amounts of renewable and Section 123 Resources were built. To ensure that cost differences between the least-cost baseline case and alternative plans were the result of differences in the mix of resources used to meet the RAP needs, the generic resources included in the least-cost baseline case for years beyond the RAP were fixed or locked down.[15] The generic resources included in the RAP for the least-cost baseline case were then replaced with increasing amounts of renewable and Section 123 Resources.

[13] See Section 2.8 of Volume 2, Technical Appendix for a description of the starting assumptions.

[14] The generic baseload plant was not available to meet any of these RAP needs given the long lead-times required to develop such a facility.

[15] The term “locked down” refers a generic resource being hardwired into the Strategist model to begin its operating life in a specific year. All generic resources “locked down” in the model were still capable of being economically dispatched with the rest of the generation 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.

Baseline Case

The least-cost baseline case utilized additional gas-fired combustion turbines to meet the resource needs during the RAP.[16] With lower capital costs and higher operating costs than the other generic technologies, combustion turbines ("CT"s) serve a "peaking" role in that they operate very few hours during the year, mostly during peak load conditions, and function to provide mostly "capacity" to the system that is needed to meet the planning reserve margin.

This result indicates that Public Service's existing and planned generation resources are capable of supplying the system's energy requirements in a cost-effective manner and that only additional peaking capacity is needed to meet the desired level of planning reserve margin. Furthermore, considering the LEC values presented in Figure 1.5-1, the generic combustion turbine was shown to provide the least-cost option within that static analysis. The fact that the generic combustion turbine also proved to be the least-cost option within the dynamic Strategist modeling makes intuitive sense when one considers that weak sales forecast, a 2,100 MW level of wind on the system by 2013, the addition of over 1,200 MW of high efficient combined cycle generation by 2016[17], and lower natural gas price forecasts were all factored into that modeling analysis.

Alternative Plans

Public Service developed a total of eight alternative plans that utilize increasing amounts of renewable generation resources and Section 123 Resources to meet the resource needs in the RAP. Four of these plans reflect a level of increased renewable resources or Section 123 Resources that could result by adding such technologies in increments of a single facility. The other four plans are more reflective of a situation where multiple facilities are added to the system. Figure 1.5-3 summarizes the components of these plans.

[16] Section 2.8 of Volume 2, Technical Appendix contains summary load and resource balances for the least-cost baseline case as well as the alternative plans.

[17] Public Service acquired the 652 MW RMEC in 2010 and plans to construct a 624 MW 2x1 CC at Cherokee by the end of 2015.

Figure 1.5-3 Least-Cost Baseline Case and Alternative Plans

RAP Resource	1 Baseline	Level A A2 Wind	A3 PV	A4 Battery	A5 Solar Thermal	Level B B2 Wind	B3 PV	B4 Battery	B5 Solar Thermal
Thermal Resources	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	1 CT 173 MW	1 CT 173 MW	1 CT 173 MW
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

Alternative Plan 2011-2050 PVRR Deltas from Baseline Case ($Millions)

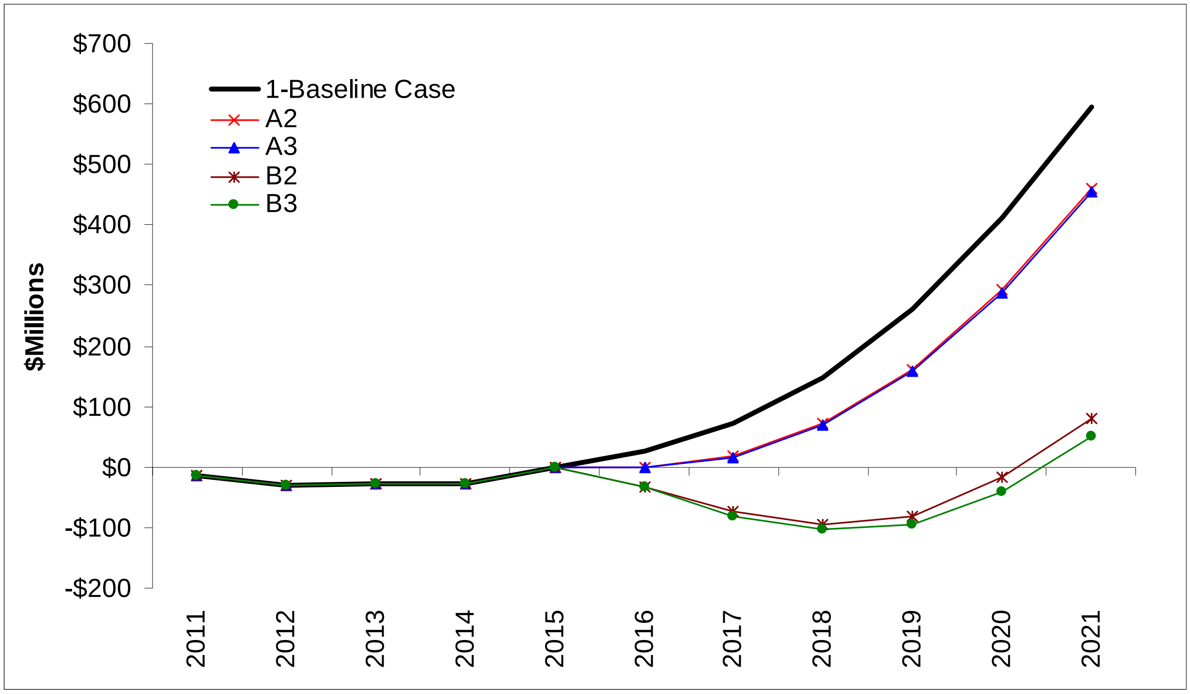
	A2	A3	A4	A5	B2	B3	B4	B5
Starting Assumptions	$98	$105	$160	$298	$427	$489	$672	$881

Note that the MW capacity values shown for renewable and Section 123 Resources in Figure 1.5-3 are nameplate ratings. The level of firm capacity equivalent that such resources provide to the system can be considerably less than their nameplate rating. As a result, it can take several hundred MWs of renewable resource additions to allow avoiding one of the 173 MW thermal CT units from the alternative plans.

Public Service adopted this “bookends” approach to provide insight into the cost and benefits of a range of renewable and Section 123 Resources. In addition to estimating the PVRR deltas from the least-cost baseline case for the eight alternative plans over the Planning Period, Strategist was used to develop estimates of how the increasing levels of renewable resources contained in alternative plans A2, A3, B2 and B3 would impact the RESA balance. Currently that balance is estimated to be in the neighborhood of a negative $30 million.[18] RESA impacts were not calculated for alternative plans A4, A5, B4, and B5 since the additional costs in these plans were the result of adding the generic Section 123 battery and solar thermal technologies which do not impact the RESA.

[18] See the 2014 RES Compliance Plan for information regarding the RESA balance.

Figure 1.5-4 RESA Impact of Baseline Case and Alternative Plans



Sensitivity Analysis

Public Service examined the robustness of the least-cost baseline case and the eight alternative plans by altering the inputs into the Strategist model for the level of sales, gas prices, tax incentives, and the price of CO_2 emissions.[19] Table 1.5-3 provides a summary of these sensitivity assumptions. Additional information is provided in Section 2.8 of Volume 2, Technical Appendix.

[19] Rule 3604(k) also identifies that the utility shall propose a range of future scenarios for the purpose of testing the robustness of the alternative plans. These sensitivity analyses comply with this requirement.

Table 1.5-3 Sensitivity Assumptions

Assumption	Sensitivity Value
CO_2 Price	3-Source blend PIRA, CERA, Wood Mackenzie, and Early CO_2
PTC Extended	Wind receives PTC (assumes PTC extended)
10% ITC Solar PV	Solar PV receive 10% ITC (assumes facility does not meet 12/31/2016 COD deadline, no extension)
30% ITC Solar Thermal	Solar thermal receives 30% ITC (assumes ITC extended or solar thermal has COD before 12/31/2016)
Low Gas Prices	1-standard deviation below starting forecast
High Gas Prices	1-standard deviation above starting forecast
Low Sales	15th percentile probability based on Monte Carlo simulation
High Sales	85th percentile probability based on Monte Carlo simulation

The sensitivity analyses for CO_2 price, tax incentives (PTC and ITC), and gas prices were performed by rerunning the least-cost baseline case and each alternative plan for years 2011-2050 in Strategist with the only change being different input assumptions for these variables. No changes were made with regard to the existing resources or to the generic resources additions included in the plans. Maintaining the same generation resources (renewable, Section 123, and thermal resources) across all Strategist model runs in this manner for both the starting assumptions and sensitivity assumptions, ensures that the PVRR differences between the plans are predominately the result of the characteristics of the resources used in the different plans to meet the RAP needs. Table 1.5-4 summarizes the results of the Strategist analysis of the plans.

Table 1.5-4 Sensitivity Results for CO_2, Tax Incentives, and Gas Price

		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
Thermal Resources	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	1 CT 173 MW	1 CT 173 MW	1 CT 173 MW
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

Alternative Plan 2011-2050 PVRR Deltas from Baseline Case ($Millions)

		A2	A3	A4	A5	B2	B3	B4	B5
	Starting Assumptions	$98	$105	$160	$298	$427	$489	$672	$881
Sensitivities	CO_2 3-Source Low Esc	$9	$10	$65	$182	$75	$113	$297	$455
	CO_2 3-Source	$7	$8	$62	$178	$63	$101	$285	$441
	CO_2 Early ($20 in 2107)	($36)	($38)	$17	$124	($117)	($92)	$98	$223
	Low Gas	$164	$179	$238	$393	$671	$760	$979	$1,204
	High Gas	$21	$19	$72	$183	$151	$176	$369	$503
	PTC Wind	($97)	($90)	($35)	$103	($312)	($251)	($67)	$142
	10% ITC Solar PV	$98	$119	$174	$312	$427	$546	$729	$938
	30% ITC Solar Thermal	$98	$105	$160	$235	$427	$489	$672	$741

Estimated 2011-2050 PVRR Impacts of Individual Renewable Energy / Section 123 Resources ($Millions)

		200 MW wind	25 MW PV	25 MW battery	50 MW solar therm	800 MW wind	100 MW PV	100 MW battery	125 MW solar therm
	Starting Assumptions	$98	$7	$55	$193	$427	$62	$184	$393
Sensitivities	CO_2 3-Source Low Esc	$9	$1	$55	$172	$75	$38	$185	$343
	CO_2 3-Source	$7	$1	$55	$171	$63	$38	$185	$340
	CO_2 Early ($20 in 2107)	($36)	($3)	$56	$163	($117)	$24	$191	$316
	Low Gas	$164	$14	$59	$214	$671	$90	$219	$444
	High Gas	$21	($3)	$53	$165	$151	$25	$192	$327
	PTC Wind	($97)	$7	$55	$193	($312)	$62	$184	$393
	10% ITC Solar PV	$98	$21	$55	$193	$427	$119	$184	$393
	30% ITC Solar Thermal	$98	$7	$55	$129	$427	$62	$184	$252

Note: For the 2011-2050 PVRR Impacts of Individual Renewable Energy/Section 123 Resources, the A5 alternative plan delta figures are calculated against the A3 alternative plan.

The low and high sales sensitivity analyses required that a new "base model" be developed within which the least-cost baseline case and eight alternative plans discussed above could be evaluated and compared with one another. The need to develop another "base model" stems from the fact that fewer or greater levels of generic resources would be needed beyond the RAP in order to serve the different levels of sales and demand contained in the low and high sales forecasts. See Tables 1.5-5 and 1.5-6 for the Low Sales and High Sales Forecasts modeling results.

Table 1.5-5 Sensitivity Analysis Results for Low Sales Forecast

RAP Resource	1 Baseline	Level A: A2 Wind	A3 PV	A4 Battery	A5 Solar Thermal	Level B: B2 Wind	B3 PV	B4 Battery	B5 Solar Thermal
Thermal Resources	0 CTs	0 CTs	0 CTs	0 CTs	0 CTs	0 CTs	0 CTs	0 CTs	0 CTs
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

Alternative Plan 2011-2050 PVRR Deltas from Baseline Case ($Millions)

	A2	A3	A4	A5	B2	B3	B4	B5
Low Sales Forecast	$125	$133	$179	$328	$545	$589	$778	$1,014

Estimated 2011-2050 PVRR Impacts of Individual Renewable Energy / Section 123 Resources ($Millions)

	A2	A3	A4	A5	B2	B3	B4	B5
Low Sales Forecast	$125	$8	$47	$195	$545	$43	$190	$425

Table 1.5-6 Sensitivity Analysis Results for High Sales Forecast

RAP Resource	1 Baseline	Level A: A2 Wind	A3 PV	A4 Battery	A5 Solar Thermal	Level B: B2 Wind	B3 PV	B4 Battery	B5 Solar Thermal
Thermal Resources	4CTs & 1 CC 1350 MW	4CTs & 1 CC 1350 MW	4CTs & 1 CC 1350 MW	4CTs & 1 CC 1350 MW	4CTs & 1 CC 1350 MW	2 CTs & 1 CC 1000 MW	2 CTs & 1 CC 1000 MW	2 CTs & 1 CC 1000 MW	2 CTs & 1 CC 1000 MW
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

Alternative Plan 2011-2050 PVRR Deltas from Baseline Case ($Millions)

	A2	A3	A4	A5	B2	B3	B4	B5
High Sales Forecast	$84	$91	$142	$368	$370	$391	$586	$764

Estimated 2011-2050 PVRR Impacts of Individual Renewable Energy / Section 123 Resources ($Millions)

	A2	A3	A4	A5	B2	B3	B4	B5
High Sales Forecast	$84	$8	$51	$277	$370	$21	$195	$373

Conclusion

Development and analysis of the least-cost baseline case and eight alternative plans provide insight as to which generation technologies are best suited to meet the RAP needs in a least-cost manner as well as how increasing amounts of renewable and Section 123 Resources can be expected to impact costs to customers. Clearly these results are influenced by the relative cost and performance estimates of the generic resources used in these analyses. Nevertheless, Public Service believes that the analysis results indicate the following:

1. the Company's existing and planned generation resources will be able to supply the forecast energy requirements of the system through the RAP in a cost-effective manner and that only additional generation capacity such as that provided by CT's is needed to maintain the desired level of planning reserve margin.

2. the addition of renewable and Section 123 Resources in these plans showed a consistent trend of increasing system costs under both starting assumptions and sensitivity assumptions.

Considering these results in light of the negative deferred RESA balance and the expectation that we will exceed the State's Climate Action Plan goals for CO_2 reductions by 2020, the Company proposes that there be no "set aside" or "targets" for renewable generation resources or Section 123 Resources established in the Phase 1 portion of this ERP proceeding. Public Service believes the more appropriate course of action is to allow the costs and benefits of renewable generation resources, Section 123 Resources and other generation resources to be evaluated within the Phase 2 competitive solicitation process using actual bids as opposed to generic estimates. In the event the Phase 2 process produces market price relationships between gas-fired generation resources and renewable or Section 123 Resources consistent with those of the generic estimates used in this analysis, the Company expects that renewable generation resources or Section 123 Resources will not be part of a least-cost portfolio. To the extent the Commission desires to see portfolios in Phase 2 that contain increasing levels of renewable generation resources or Section 123 Resources the Commission can direct the Company to produce such generation resource portfolios in its Phase 1 order.

We note that while continued operation of the Arapahoe 4 and Cherokee 4 units on gas were included in the least-cost baseline case as well as the eight alternative plans, the Company will evaluate alternatives to running these units on natural gas and report the results of this evaluation in its Phase 2 120-Day Report.[20]

[20] As ordered in Commission Decision No. C10-1328, Ordering Paragraphs 116 and 135.

1.6 RESOURCE ACQUISITION PLAN

Overview

At the conclusion of the 2011 ERP Phase 1 proceeding, the Company proposes to utilize a competitive solicitation process to acquire the additional generation resources needed to meet the resource need for the seven-year RAP (October 2011 – October 2018). In an effort to ensure full consideration of all available generation resource options, Public Service proposes issuing an All-Source Solicitation in which all supply-side electric generation resources with a nameplate electric rating of 10 MW (AC) or larger would be eligible for consideration.

The Company also seeks Commission approval to employ an "opportunistic" approach for acquiring renewable generation resources and or Section 123 Resources during the time period between this 2011 ERP and the 2015 ERP. Given that the All-Source Solicitation will acquire additional generation resource capacity needed for reliability purposes, there will be specific timing requirements for issuance, evaluation, and selection of proposals such that selected generation resources can be in service when needed. While there may be no need for additional renewable generation resources or Section 123 Resources for reliability needs, market conditions may create, from time to time, renewable resource or Section 123 Resource energy prices that are favorable to our customers and which warrant the Company issuing an RFP.

All-Source Solicitation

RP Rule 3611(a) establishes that a competitive acquisition process will normally be used to acquire power supply resources and that the process should afford an opportunity for all technologies to bid. Public Service's proposal to use an All-Source Solicitation process to solicit, evaluate and, select the needed power supplies complies with this Commission rule. While RP Rule 3615(a) (III) allows the Company to acquire power supplies less than 30 MW outside of an approved ERP, to better ensure full consideration of all available power supply options, Public Service proposes that supply-side electric generation technologies with a nameplate electric rating of 10 MW (AC) or larger would be eligible for consideration in the All-Source Solicitation. A 10 MW minimum generation project size will allow the Company to determine if the credits afforded to supply-side resources interconnecting at distribution voltage can overcome lower cost energy from larger projects (which typically come with economies of scale) employing similar generation technologies that interconnect at transmission voltage. The Company believes that a minimum bid size that is too low can result in unwarranted numbers of bid submissions. Given the 120-day compressed time frame within which we must complete our bid evaluation, the Company believes that a 10 MW minimum size strikes a reasonable balance between allowing bids from distribution-interconnected projects and maintaining a manageable volume of bids to evaluate.

If power supply proposals are to serve a portion of the RAP need, they must begin generation prior to the summer peak of 2018. Therefore, to provide some allowance for contract negotiation or development schedule delays, to be eligible for consideration in the All-Source Solicitation, all power supply bids must propose a commercial operations date no later than May 1, 2018.

Key Aspects of All-Source Solicitation

Short-term bids

As established elsewhere in this document, the existence of an overbuilt power supply market along with a host of other factors presents a unique opportunity for the Company to utilize short-term bids to help serve the capacity needs that will ultimately be sought in the All-Source Solicitation. The Company believes that short-term commitments can bring additional value to our customers in the form of added flexibility in future ERPs to reassess whether continued utilization of the power supplies associated with these short-term PPAs still makes sense for our customers versus other options. Whether or not such a strategy proves beneficial for customers ultimately rests with the owners of existing generation facilities and the prices they are willing to offer to the Company. Since these existing generators have already completed at least one-cycle of PPA's with the Company and have recouped much of their initial investment of their plants, it seems logical that they would be in a position to offer pricing below that of a newly constructed generation facilities. To the extent these owners have a differing view of the value of their generation assets, Company self-build alternatives will discipline the process.

For the facilities owned by IPPs or other utilities, short-term bids would take the form of a power purchase agreement that begins prior to May 1, 2018 and continues at least through the end of the RAP (October 31, 2018) but not beyond December 2025.

The All-Source Solicitation will also allow bidders proposing to construct new generation facilities to offer those facilities to the Company under short-term PPA's that expire by December 2025. While it is not anticipated that the pricing from such offers would be below those offered by owners of existing facility's the RFP, short-term offers for newly constructed facilities will be considered.

Long-term bids

To help provide pricing discipline to the short-term bids, the All-Source Solicitation will also seek power supply proposals offering PPA terms that extend beyond December 2025. Bidders will be allowed to offer PPAs up to a twenty five year term.

Bidders of existing facilities will also be allowed to offer the sale of those assets to Public Service if the acquisition will provide additional generation capacity to the Company that can be used to meet a portion of the RAP resource need.

Company Self-Build Proposals

Public Service will provide sufficient utility-owned self-build power supply proposals into the Phase 2 competitive solicitation process to meet the entire need for new resources over the RAP. This will ensure that within the Phase 2 evaluation process at least one portfolio can be developed that meets the RAP need entirely with Company-owned facilities.

Company proposals will be sufficiently vetted such that the actual cost for constructing the proposed facilities will be within 20 percent of the cost contained in the proposals. Company proposals will also be sufficiently vetted such that the operation and maintenance costs for the facilities will be within 20 percent of the costs contained in the proposal.

The Company expects to offer self-build proposals that expand the generation capacity at existing generation sites. Expanding the generation capability of an existing generating site is referred to as “brownfield expansion” or a “brownfield” facility. In contrast, constructing a new generation facility at a previously undeveloped site is referred to as a “greenfield” facility. Existing Company sites that can accommodate expansion include Cherokee, Ft. Saint Vrain, Rocky Mountain Energy Center, and Blue Spruce Energy Center. The Company expects these brownfield expansion opportunities to offer very cost-effective long-term options that will discipline both short-term and long-term bid pricing from IPPs and other utilities.

<u>Operation of Arapahoe 4 and Cherokee 4 on Gas</u>

As discussed in more detail in Section 1.7 below, the Company will assess alternatives to running Arapahoe 4 and Cherokee 4 on natural gas as directed by the Commission in Decision No. C10-1328 in the Clean Air-Clean Jobs Act docket, so long as alternatives meet or exceed the emission reductions achieved by the fuel conversion plans. This process will utilize bids received in response to the All-Source

RFP as potential alternatives. Given that recently completed transmission studies[21] indicate that adequate transmission reliability can be achieved by implementing identified transmission reinforcements, such that “must run“ operation for Arapahoe 4 and Cherokee 4 is not necessary, both Arapahoe 4 and Cherokee 4 will operate on gas as peaking resources providing mainly generation capacity value to the system.

To be clear on this matter, the Company is not offering up early retirement of Arapahoe 4 or Cherokee 4 as part of its 2011 ERP filing. The Company is proposing to operate these facilities on gas from January 1, 2014 until December 31, 2023 and from January 1, 2018 until December 31, 2028, respectively. Current projections for the on-going fixed costs for Arapahoe 4 and Cherokee 4 are in the range of $3–5/kW-month, which is below what the Company has seen in past RFPs and well below our generic estimates for new peaking capacity. Consequently, it may be very difficult to find a competitive replacement for this generation. Nevertheless, the Company will assess whether there is a more cost-effective way to provide this peaking power.

Opportunistic Approach for Acquiring Renewables

RP Rule 3615(a)(III) specifies that the Company may acquire incremental capacity and/or energy from generation resources 30 MW or less outside of an approved resource plan. RP Rule 3656(a) allows a similar exemption to acquire renewable resources less than 30 MW outside of an approved RES plan. The Company’s ability to acquire renewable resources greater than 30 MW, however, is governed by a requirement to do so within the context of an approved ERP. Given fluctuations in the market price of renewable generation resources, the Company believes that being limited to assessing renewable resources greater than 30 MW in an All-Source Solicitation issued only every four years does not provide sufficient flexibility for us to acquire such resources when markets are most favorable for our customers. Therefore, as part of this 2011 ERP, the Company is requesting that the Commission approve Public Service conducting targeted solicitations from time to time to acquire additional renewable energy resources, subject to Commission review and approval of the renewable energy resources selected through these targeted solicitations.

The Company believes that it is in our customers’ best interests that we be allowed to respond promptly to opportunities to acquire renewable energy resources larger than 30 MW, to the extent these resources can be acquired at or below our projected avoided costs. Opportunities to acquire such resources might arise from increased Federal or State stimulus funds, new or extended tax credits, or other incentives. Or, they might arise from a short-term imbalance between supply and demand for new generation equipment. Waiting until the next quadrennial resource

[21] See Sections 2.15 and 2.16 of Volume 2 Technical Appendix for these studies.

plan to acquire these resources could cause us to forego the opportunity to acquire very cost-effective renewable energy resources for our customers.

Demand-Side Management

The determination of resource need during the RAP will account for the impacts that the Company's existing and planned DSM and interruptible programs have on reducing the peak hour load. The Commission has established separate processes outside the ERP by which the appropriateness of the Company's proposed level of DSM achievements are reviewed and approved. On August 10, 2010, the Company filed an application for approval of a number of strategic issues relating to our 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. 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 our energy efficiency initiatives, Savers Switch, the Interruptible Service Option Credit (ISOC) and Third Party Demand Response programs in our application for approval of our 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 its 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). As a result, while the Company will continue to use competitive bidding to solicit vendors to assist it in implementing its approved DSM plans, the Company will not accept bids offering additional DSM resources as part of the 2011 ERP All-Source Solicitation.

Resource Acquisition Plan Summary

The Company's proposed resource acquisition plan for this 2011 ERP contains the following key elements:

1. A competitive All-Source Solicitation will be used to acquire new supply-side resources needed to meet the planning reserve margin targets. All supply-side generation technologies will be allowed to compete and the Solicitation will allow bids for supplies with an electric rating of 10 MW AC or more. The All-Source Solicitation will seek both short-term and long-term power supply proposals with a preference for short-term contracts. The Company proposes

that there be no set-asides or specific targets for renewable or Section 123 Resources for the All-Source Solicitation. To the extent the Commission desires to see portfolios from the Phase 2 process that contain increasing levels of renewable or Section 123 Resources the Commission should direct the Company to do so in its Phase 1 order.

2. A request for Commission approval to pursue an "opportunistic" approach to acquiring additional renewable resources. Specifically, the Company requests Commission approval to issue RFP's, from time to time, and to evaluate bids for new renewable resources greater than 30 MW as well as consider unsolicited proposals, during the timeframe between this 2011 ERP and the 2015 ERP. The Company will seek Commission approval of any projects that result from this process.

3. Prior to the computer modeling of All-Source RFP bid portfolios during the Phase 2 process, the Company will assess alternatives to continued operation of Arapahoe 4 and Cherokee 4 on gas.

4. The Company will offer enough utility-owned self-build power supply proposals into the Phase 2 competitive solicitation process to meet the entire need for new resources over the RAP. Company proposals will be sufficiently vetted such that the actual cost for constructing the proposed facilities will be within 20 percent of the cost contained in the proposals. Company proposals will also be sufficiently vetted such that the operation and maintenance costs for the facilities will be within 20 percent of the costs contained in the proposal. Company resources will be evaluated at their expected cost.

1.7 PHASE 2 COMPETITIVE SOLICITATION AND EVALUATION

The Company proposes to acquire additional generation resources to meet the RAP needs through an All-Source Solicitation. 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. The Company believes the process laid out below meets these new requirements. More detailed information regarding the Phase 2 solicitation and evaluation process is contained in Section 2.9 of Volume 2, Technical Appendix.

The discussion in this section is organized into four categories:

1. RFP release and initial bid due diligence;
2. Initial economic analysis and screening;
3. Assessment of Arapahoe 4 and Cherokee 4;
4. Computer modeling of bids and development of portfolios.

RFP Release and Initial Bid Due Diligence

Company Activities Following the Release of the RFP

The Company anticipates issuing the All-Source Solicitation 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: 1) a Dispatchable Resources RFP, 2) a Renewable Resources RFP, and 3) a Semi-Dispatchable Renewable Capacity Resources RFP. The Company anticipates that it will hold a Pre-Bid Meeting approximately three (3) weeks following the issuance of the All-Source Solicitation.

Bid Eligibility Screening and Initial Due Diligence

Upon receipt of the bids, the Company will categorize the bid by its proposed generation source and conduct a review of each bid to ensure it meets the minimum bid eligibility requirements. Even though different technologies will be requested to respond to a resource technology specific RFP, all bids will be competing against one another to meet the Company's resource need.

The Company intends to notify all RFP respondents within 15 days of bid receipt as to the Company's bid eligibility evaluation.

Initial Economic Analysis and Screening

Assignment of Transmission Interconnection and Network Upgrade Costs

The Company will assign incremental transmission interconnection costs and/or network upgrade costs to each bid to ensure each proposed project will qualify as a network resource. 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 certificate of public convenience and necessity ("CPCN").[22]

Initial Economic Screening

The initial economic screening consists of calculating an "all-in" levelized cost of energy ("LEC"). LEC calculations include proposed pricing, any incremental interconnection and/or network upgrade costs, and any applicable resource integration costs. Projects that propose to interconnect at distribution voltages will be credited with avoided line losses in their LEC calculations. No renewable energy credit ("REC") value benefits will be assigned. The Company will employ its after-tax weighted average cost of capital ("WACC") in the present value calculations.

Assessment of Arapahoe 4 and Cherokee 4 on Natural Gas

Through a process that will occur prior to the computer modeling of All-Source RFP bid portfolios, the Company will assess alternatives to running Arapahoe 4 and Cherokee 4 on natural gas. This process will utilize bids (individually or in combination with other 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. For any individual bid or group of bids to be considered as a potential alternative to Arapahoe 4 on natural gas, they must provide approximately 109 MW of firm generation capacity and must provide this level of MW starting during the RAP and continuing through at least 12/31/2023 (the retirement date of Arapahoe 4), but no longer than 12/31/2025 (in order to qualify as a short-term bid). For any individual bid or group of bids to be considered as a potential alternative to Cherokee 4, they must provide approximately 352 MW of firm generation capacity and must provide this level of MW starting at some time during the RAP and ending 12/31/2025.

The analysis of potential alternatives will focus on a comparison between the $/kW-mo fixed costs of Arapahoe 4 and Cherokee 4 with the $/kW-mo fixed cost of bids (individually and in combination) offering short-term PPAs from existing dispatchable gas-fired generating facilities. To the degree the short-term bids under consideration offer higher or lower heat rates than the heat rates of Arapahoe 4 and Cherokee 4, the fixed capacity cost of such bids will be adjusted up or down to reflect the value of that heat rate differential. Public Service will complete this assessment outside of the Strategist model.

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

[22] 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.

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 and all Company self-build projects will be advanced to computer modeling and portfolio development. The Company will also pass forward a sufficient quantity of bids across the various generation resource types such that portfolios 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 a sufficient volume of such bids are received.

Pursuant to ERP Rule 3613(a), 45 days after bids are received the Company will inform each bidder as to whether its bid has been advanced to portfolio development. For those bids not advanced to portfolio development, the Company will provide the reason(s) why the project will not be evaluated further. For those bids advanced to 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

LEC calculations are useful in the economic screening of bids where the main objective is to winnow down the pool of proposals to be advanced for additional consideration and analysis. Differences in how and when certain generation technologies produce energy, however, limit the ability to utilize LEC for purposes of determining how a particular bid or group of bids (a "portfolio") interact with Public Service's existing generation resources to serve the system needs over time. To capture these interactions and their impacts on the overall electric system costs over the Planning Period, it is necessary to perform a more comprehensive analysis that utilizes computer-based programs such as Strategist. The Strategist model contains all the variables needed to simulate the operation of the Public Service system as well as bids offering new resources that are needed to meet future demand growth. The model calculates the total system cost of serving the forecast of customer electric energy needs over the Planning Period and ranks each feasible combination of portfolios by lowest to highest PVRR.

Bid Portfolio Modeling Framework

The objective of computer modeling is to develop bid portfolios that meet the identified RAP need in the most cost-effective manner, consistent with the Commission Phase 1 order. The modeling framework Public Service plans to utilize to accomplish this objective 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 be used to extend all bids to the end of the Planning Period.

Following is a summary of the modeling framework to be applied in the evaluation of bids received from the competitive solicitation process. Additional details are provided in Section 2.9 of Volume 2, Technical Appendix.

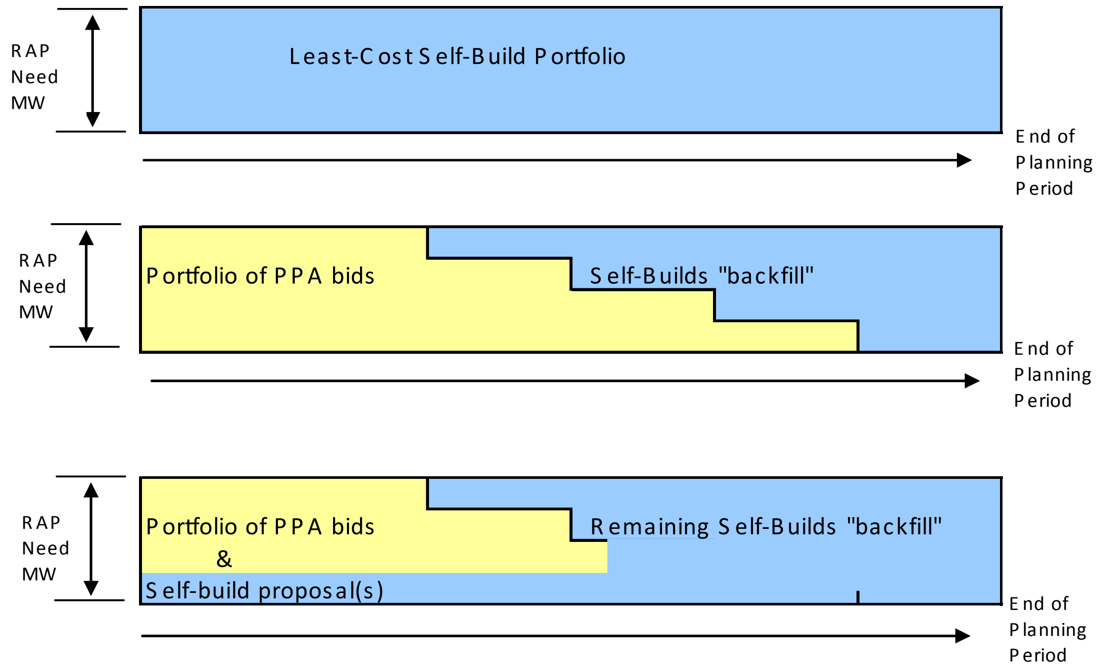
Construct Base Model – using 1) the modeling assumptions approved by the Commission in its Phase 1 decision, 2) the Company's most up-to-date forecasts for items such as sales, DSM goals, and fuel prices, and 3) the results of the Company's assessment of alternatives to burning gas in Arapahoe 4 and Cherokee 4, the Company will construct a representation of the Public Service electric supply system as was done for Phase l least-cost baseline and alternative plan cases.

Develop "Least-Cost" Self-Build Portfolio – starting with the base model described above, a least-cost portfolio that meets the RAP needs with Company self-build proposals only will be developed. The capital cost and operating costs of Company self-build proposals will be represented at their expected values. The useful lives of Company proposals will extend through the end of the Planning Period; therefore, no assumptions need be made on how to extend the lives of Company proposals. These Company self-build proposals will replace the generic resources used in the Phase 1 analyses.

Develop Bid Portfolios – starting with the base model, portfolios of bids and Company proposals will be developed that meet the same RAP needs as the self-build portfolio described above. Portfolios that meet the RAP need utilizing bids that do not extend to the end of the Planning Period will be "backfilled" with the proposals that comprise the "least-cost" self-build portfolio.[23] The Strategist model will be allowed to determine when each of the Company 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. Figure 1.7-2 provides a simplified illustration of how this will work for two different hypothetical portfolios of PPA bids.

[23] The capital costs of these self-build proposals will be represented using an economic carrying charge in the model optimization.

Figure 1.7-2 Illustration of Proposed Method to Backfill Portfolios



The first portion of Figure 1.7-2 illustrates how a portfolio that meets the entire RAP need with self-build proposals would extend to the end the Planning Period. The second portion illustrates how a portfolio that meets the entire RAP need with PPA bids would be backfilled with the self-build Company proposals at the end of the PPA terms. The third portion of Figure 1.7-2 illustrates how a portfolio that meets the RAP need with a combination of self-build and PPA bids would backfill the PPA bids at the end of their terms.

Sensitivity Analysis of Portfolios

A set of portfolios utilizing a range of technologies to meet the RAP needs will be selected for sensitivity analyses. A sufficient number of portfolios will be advanced to ensure a diverse set of generation technologies are represented as well as a diverse set of PPA term lengths. The Company will consider the following factors when deciding which portfolios to advance.

1. *Short-term Bids* – the Company has stated a preference for short-term PPAs to the extent they are cost-effective when compared with longer term bids. A sufficient number of portfolios will be advanced to represent the value of meeting all or a portion of the RAP needs with short-term PPAs.
2. *Existing Facility Bids* – to the extent existing facilities offer long-term PPAs, a sufficient number of portfolios will be advanced to represent

the value of meeting all or a portion of the RAP needs with long-term PPAs.

3. *Renewable Technologies* – a range of the renewable technologies offered into the competitive solicitation process will be represented in the portfolios.
4. *Section 123 Technologies* – a range of the Section 123 technologies offered into the competitive solicitation process will be represented in the portfolios.
5. *Company Self-Build Proposals* – portfolios meeting the entire RAP need as well as only a portion of the RAP need with self-build proposals will be advanced.
6. *Planning Period PVRR* - the Company will use planning period PVRR (calculated using starting assumptions) as a key metric in determining the number of portfolios to advance.

The PVRR of portfolios advanced for sensitivity analyses will be recalculated under different assumptions for gas prices, construction escalation rates, and CO_2 emission costs. As was done in the analysis of the least-cost baseline case and alternative plans, the mix of bids used to meet the RAP needs as well as the generic resources included beyond the RAP in each portfolio will be fixed or locked down when the portfolio PVRRs are recalculated under each sensitivity. This will ensure that cost differences between portfolios will be the result of differences in the factors being studied in the sensitivity analyses and not due to changes in the mix of resources.

Additional information on the sensitivities is contained in Section 2.8 of Volume 2 Technical Appendix.

RESA Impact Analysis of Portfolios

Portfolios advanced to sensitivity analysis will also be analyzed to estimate their impact on the RESA. An abbreviated analysis will be employed to develop these estimates in which the annual incremental costs or benefits will be estimated for each portfolio that result from renewable resources in the RAP. These incremental costs or benefits will be added to or subtracted from the RESA impacts for the least-cost portfolio.

120-Day Report

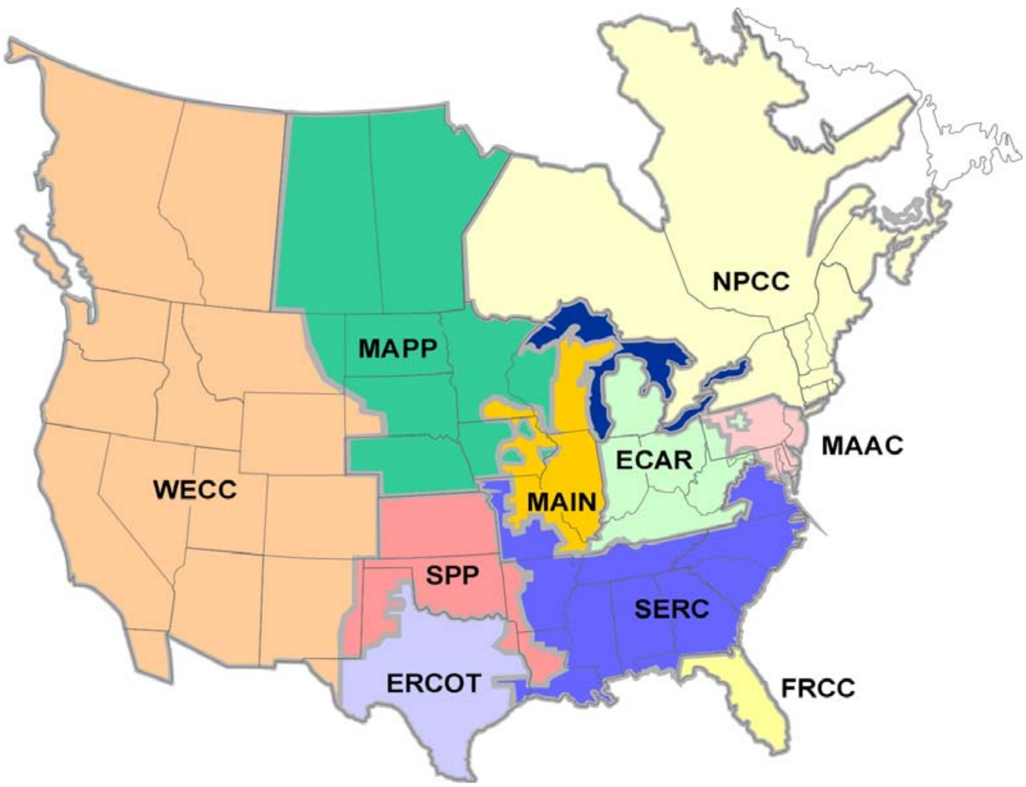
Within 120 days of receiving bids in response to the Phase 2 competitive acquisition process, Public Service will file a report with the Commission describing its bid evaluation results including cost-effective resource plans that conform to the Commission's Phase 1 decision approving or modifying the 2011 ERP. Public Service will set forth its Preferred Portfolio and explain why we have chosen that portfolio.

1.8 RESERVE MARGIN AND CONTINGENCY PLAN

Planning Reserve Background

The reliability of the electrical system of North America is guided and coordinated by the North American Electric Reliability Corporation ("NERC"). NERC is comprised of ten separate regional councils.

Figure 1.8-1 Regional Reliability Councils of NERC



Public Service is a member of and regularly participates in the activities of the following groups:

- Western Electricity Coordinating Council ("WECC")
- Rocky Mountain Reserve Group ("RMRG")
- Westconnect

The WECC is one of the ten NERC regional councils established to promote the reliable operation of the interconnected bulk power system of the western United States and Canada. The WECC does not publish recommended or required planning reserve criteria for its member systems, but rather allows individual member systems (including regulatory Commissions) to adopt their own planning reserve criteria. WECC does, however, perform Power Supply Assessments (“PSA”) of its member systems annually. The purpose of the PSAs is to identify WECC subregions that have the potential for electricity supply shortages based on reported demand, resource, and transmission data. During these annual PSA reviews Public Service provides WECC with detailed information regarding the Company’s electric supply system including:

- Generation rating data
- Actual and Forecasts of demand
- Characteristics of Demand
- General System data

WECC combines this data with that of other member systems to model the interconnected systems and assess the reliability for the upcoming summer and winter seasons.

The latest 2010 PSA evaluated generation resource reserve margins (in MW) for the WECC summer and winter peak hours for the forecast period 2011 through 2019. Public Service’s reserve margin level and basis for that level (discussed below) were found to be acceptable by WECC.

Reliability Planning at Public Service

Public Service strives to provide electric service at all times to our firm customers. To accomplish this, the Company works to maintain an adequate supply of electric generation to meet the expected maximum demand of our customers (i.e., the “peak” demand or load) for a reasonable set of unforeseen events (power plant outages, higher than expected load etc.). To maintain service to firm customers, Public Service utilizes a combination of measures and practices, each focusing different time horizons - real-time, mid-term, and long-term.

Real-time

Ultimately it is the real-time status of the system that determines whether supply is sufficient to maintain service to firm load customers. Real-time in this context refers to the measures and practices the Company employs each day in operating the electric system. These entail carrying sufficient operating reserves to ensure that ample resources are available to serve load. Operating reserves are generation capacity that is either on-line and unloaded, i.e., spinning, or that can be brought on-line and synchronized to the grid in short order.

As a member of the RMRG, Public Service carries operating reserves in accord with the RMRG established methodology. Public Service's current RMRG contingency operating reserve obligation is 381 MW.

Mid-term
To better ensure sufficient resources are available to meet the real-time needs of the system, Public Service evaluates the need for short-term capacity and energy several months (but generally less than a year) in advance of each summer peak season. In the event that this mid-term supply adequacy evaluation determines that the installed reserves for the upcoming summer peak are likely to fall below the desired reserve level, the Company will pursue purchasing short-term capacity. In recent years, the Company has been able to secure approximately 200-300 MW of short-term capacity for the summer months.

Long-term
Long-term activities involve the acquisition of additional generation resources or demand reduction to meet the long-term electric demand projections. The amount of installed generation capacity in excess of the annual system peak demand is commonly referred to as "planning reserve margin" or "planning reserves". Long-term in this context refers to a future period up to 10 years (or longer) over which the Company acquires additional resources through the Commission's ERP process. The reserve margin target used in the long-term planning of the system influences the Company's ability to meet the future mid-term and, ultimately, the real-time capacity needs of the system. The remaining discussion will focus on the "planning reserve margin" Public Service will employ in the acquisition of future resources in the 2011 ERP.

Planning Reserves for the 2011 ERP

For the 2011 ERP, Public Service proposes to utilize a planning reserve margin target of 16.3% in assessing the need for additional power supply resources. This 16.3% value will be applied to the Company's projection of annual firm peak demand[24] over the RAP to determine the amount of additional power supply, if any, the Company should seek to acquire in this ERP in order to maintain acceptable long-term system reliability. The appropriateness of a 16.3% planning reserve target for the Public Service system was established in a study performed by Ventyx,

[24] Annual firm peak demand to which the 16.3% reserve margin target will be applied is represented by taking the 50th percentile forecast of total peak demand projection and subtracting 1) the effects of the Company's DSM efforts, 2) interruptible program loads, and 3) savers switch customer loads

developers of the Strategist and PROSYM models, for Public Service in late 2008. The study scope was established through a collaborative effort between the Commission Staff, the Office of Consumer Counsel, and the Company. The study determined that a 16.3% planning reserve margin for the Public Service system would result in a "loss of load probability" of 1-day in 10-years, a common industry standard for an acceptable level of system reliability. The study used 2013 as a test year to ensure the effects of the Comanche 3 facility were captured and took into consideration the hourly Public Service customer electric demands and the volatility of those demands due to weather. The analysis also incorporated the reliability support that Public Service could expect to receive from RMRG under single contingency events of 200 MW or greater as well as the Company's obligation to carry 381 MW of operating reserves as part of our membership in the RMRG. Additionally, the analysis considered the effects of wind generation on the system as well as the reliability contribution of transmission lifeline capacity generally reserved for system emergencies.

A copy of the study is included as Attachment 2.10-1 in Volume 2, Technical Appendix of this 2011 ERP.

Contingency Plan

Public Service recognizes that matching electric generation with customer demand will not always proceed according to plan. Problems can arise as a result of delays in the in-service dates of new generation facilities, contract negotiations with suppliers can breakdown, and unanticipated increases in the customer demand can arise that Public Service is obligated to serve. While it is impossible to anticipate everything that can occur in the resource acquisition process, we can anticipate the more common contingencies and develop plans to address them. This section of the 2011 ERP identifies what the Company believes to be the most likely situations it might face in the resource acquisition process and identifies contingency alternatives available to Public Service to address them. The discussion will focus on events or situations that create the potential for a capacity shortfall if corrective action is not taken.

Contingency Events

We anticipate that the more relevant and probable contingency events will include, but are not limited to:

1. Failed contract negotiations with winning bidders
2. Bidders withdrawing proposals
3. Bidders seeking revised terms from those in their bid
4. Project development delays or cancellation
5. Transmission development delays
6. Higher than anticipated electric demand

Contingency Plan Options

The following is a list of options available to Public Service to remedy any unanticipated resource shortfall:

1. Initiate negotiations with other / replacement bidder(s)
2. Hold a targeted RFP to replace a selected project that has failed
3. Advance the in-service date of other selected projects
4. Purchase short-term capacity from off system, existing generation supplies
5. Issue additional non-targeted RFP(s) to satisfy anticipated shortfalls
6. Construct and own additional new generation capacity
7. Arrange temporary generation
8. Implement interim Load Management / Customer generation plans
9. Modify contracts with existing suppliers
10. Sole source with an IPP to construct additional generation
11. Increase Demand Side Management
12. Some combination of (1) through (11)

Critical Factors

Two critical factors dictate whether a corrective action provides a viable solution for a particular contingency event. These factors are:

1. The magnitude of the potential resource shortfall, and
2. The timing associated with the potential capacity shortfall – both the lead-time to the contingency and the duration of the event.

The magnitude of an anticipated capacity shortfall dictates the available options Public Service can pursue. For example, a capacity shortfall of 50-100 MW might be addressed through contracting short-term purchases from existing generation supplies. Short-term capacity purchases would likely be ineffective in addressing a 500 MW shortfall.

Similarly, the timing of an anticipated capacity shortfall dictates the number of available options Public Service can pursue. Timing in this case includes both the duration of the shortfall and when it is expected to occur. Capacity shortfalls projected to occur within a year for example would likely exclude the option of constructing new generation and transmission facilities. By contrast, a capacity shortfall projected to occur several years in the future could be addressed through a variety of actions including new construction, initiating negotiations with other bidders or issuing an RFP.

Likewise, a delay of a new generation resource or of the transmission needed for a new resource might best be addressed by a temporary or interim solution, like temporary generation facilities, short-term purchases, or interim load management, as opposed to the permanent addition of another new generation project or new Company constructed and owned generation facilities – unless there were a long-term need for additional resources.

Corrective Actions

In the event Public Service faces a capacity shortfall situation, the appropriate course of action will depend largely on the specifics of the shortfall itself, i.e., magnitude and timing, as well as a variety of other factors, e.g., market conditions, other acquisition activities underway. As such, Public Service will always need to apply judgment as to how we should proceed when deciding what corrective action to pursue. For this reason, the Public Service contingency plan reflects a large degree of flexibility in how we plan to address various contingencies. Table 1.8-1, Hierarchy of Contingency Plan Alternatives, lists several possible approaches for addressing contingencies that might require corrective action over the acquisition period. This hierarchy depends on how long before the event Public Service becomes aware of the contingency, the expected duration of the contingency, e.g., a delay vs. the permanent loss of a planned resource, and the magnitude of the contingency.

Table 1.8-1   Hierarchy of Contingency Plan Alternatives

1.	Short-term capacity purchases	Save for "late breaking" contingencies for which there might not be time to use one of the following corrective actions
2.	Use alternative bids	If the contingency becomes known before Public Service has released bidders from their obligation, Public Service would use this corrective action. This corrective action is most appropriate for replacing 1st winning bids that drop out soon after selection or do not reach successful contract completion.
3.	Accelerate in service date of resources for which contracts have been executed or for self-build projects already been approved	If the contingency becomes known sufficiently ahead of time, negotiate an earlier in service date for a resource planned for later in the acquisition period. This corrective action is most appropriate for a one to two year delay in another resource.
4.	Public Service builds back-up bids	If the contingency becomes known in time for Public Service to build its own facility, Public Service will self-build a facility to cover the contingency through the use of the back-up bid that will be filed with the Commission at the time the bids for the RFP are due to be submitted to the Company.
5.	Sole source with reliable supplier	This option could substitute for Public Service building its back-up bid if time does not permit the Company to complete the necessary construction in a timely manner. Effectively, Public Service would approach an IPP with whom it has had a good working relationship and sole source a new supply either from an existing facility or possibly an expansion of an existing facility..
6.	Install Temporary Generation	The Company or an IPP can implement this measure with somewhat less lead-time than the installation of new permanent generation and it is well suited to cover a generation project or transmission delay that may last a year or possibly two.
7.	Implement interim Load Management or Customer Generation Programs	Similar to the installation of temporary generation, this measure can be implemented in a relatively short lead-time, e.g. within 6 months, and is well suited to address resource delays.
8.	Reduced reserve margin	If the contingency became known too late to add new resources in time and insufficient short-term purchases were available to cover the contingency, Public Service could operate with a reduced planning reserve margin but with the required operating reserve margin for a summer season until one or a combination of the other

		corrective actions could be put into place.

Public Service and other Xcel Energy Inc. electric operating companies have successfully applied many of these contingency actions in the past. Xcel Energy Inc.'s other utility operating companies also have experience with many of these measures and Public Service can draw upon a wide range of resources, experience and capabilities in order to respond in the most appropriate way to contingencies that might develop during the RAP for the 2011 ERP.

1.9 CONFIDENTIAL AND HIGHLY CONFIDENTIAL INFORMATION

The treatment of proprietary information used in the Phase 1 and the Phase 2 resource planning processes was an issue during the review of the 2007 ERP. More parties now seek to review information used in the development of the resource plan to develop positions on resource issues and to ensure fair consideration of proposals for generation resources. To afford better information access to perform these reviews, while also maintaining the ability to safeguard proprietary information, the Commission revised the ERP Rules. The ERP Rules require that Public Service list the information that Public Service will seek to protect in Phase 1 and Phase 2. Specifically the Rule 3604(j) requires that Public Service provide:

> A list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information related to the resource plan proceeding that the utility claims is highly confidential. The utility shall also list the information that it will provide to owners or developers of a potential resource under paragraphs 3613(a) and (b). The utility shall further explicitly list the protections it proposes for bid prices, other bid details, information concerning a new resource that the utility proposes to build and own as a rate base investment, other modeling inputs and assumptions, and the results of bid evaluation and selection. The protections sought by the utility for these items shall be specified in the motion(s) submitted under paragraph 3603(b). For good cause shown the utility may seek to protect additional information as confidential or highly confidential by filing the appropriate motion under rule 1100 of the Commission's Rules of Practice and Procedure in a timely manner.

Public Information

The following Public Service information that is relevant to the 2011 ERP is, or will be, public information as the result of Public Service's either filing the information in Phase 1 or Phase 2 of the 2011 ERP or as the result of a prior filing with the Commission, the State of Colorado or with federal agencies:[25]

Public Service Company of Colorado Information

- Sales by Customer Class
- Revenue by Customer Class
- Number of Customers by Customer Class
- Sales by Tariff
- Revenue by Tariff
- Sales per Customer by Tariff

[25] Information listed is not all inclusive.

- Revenue per kWh by Tariff
- Sales Made to Wholesale Customers
- Revenue from Sales to Wholesale Customers
- Affiliate Transactions
- Reserve Margin
- Contingency Plan
- Resource Need for Resource Acquisition Period
- Renewable Energy Standard
- RES Compliance Position
- Renewable Energy Standard Adjustment
  - Balance
  - Forecast
- Sales and Demand Forecast
  - Total Sales
  - Total Demand
  - Sales by Customer Class
  - Demand by Customer Class
- Aggregate CO_2 Cost Projection

<u>Company-Owned Generation Resource Information</u>

- Aggregate Cost of Production
- Energy Production
- Depreciation and Amortization Expense
- Estimated Average Service Life
- Peak Load
- Plant Hours Connected to Load
- Capacity
- Plant Production Costs
- Average Cost pre kWh
- Average Heat Rate
- Total Fuel Consumed
- Fuel Types
- Capacity Factor
- Availability Factor
- Estimated Remaining Useful Lives
- Total Emissions by Type
- Plant Emissions by Type
- Total Fuel Used by Type
- Fuel Cost
  - Historical Coal Cost
  - Historical Gas Cost
  - Coal Cost Projection
  - Gas Cost Projection

<u>Purchased Generation Resource Information</u>

- Capacity
- Energy Purchased
- Cost of Energy Purchased
- Contract Duration
- Contract Modification Terms

Transmission Resource Information

- Operating Costs
- Wheeled Energy
- Wheeled Capacity
- Wheeling Revenue
- Purchase and Sale of Ancillary Services
- Peak Load
- Line Size and Length
- Capacity from Wheeling and Coordination Agreements
- Planned Additions
- Injection Capability

Strategist Model Data

Input Information

- Inflation Rate
- Federal Tax Rate
- State Tax Rate
- Discount Rate
- Weighted Average Cost of Capital
- Variable O&M Escalation Rate
- Fixed O& M Escalation Rate
- Construction Cost Escalation Rate
- SO2 Pricing
- NOx Pricing
- CO2 Pricing
- Wind Integration Costs
- Wind Related Coal Cycling Costs
- Solar Integration Costs
- Natural Gas Price Volatility Mitigation Adder (PVM)
- Annual / Monthly Peak Demand
- Annual / Monthly Total Energy Demand
- Line Loss Assumptions
- DSM Forecast
- Load Management Resources
- Reserve Margin Requirements
- Spinning Reserve Requirement

- Wind Curtailment Pricing
- System Average Colorado Coal Prices
- System Average PRB Coal Prices
- Blended Natural Gas Prices – not proprietary forecasts
- Oil Prices
- Capacity Credit Pricing
- Capacity Credit Limits
- In-Service Dates
- Retirement Dates
- Unit Capacities
- PPA In-service Dates
- PPA Retirement Dates
- PPA Capacities
- Generic Resources
    - Name Plate Capacity
    - Summer Peak Capacity
    - Capital Costs
    - Transmission Interconnection Costs
    - Transmission Grid Upgrade Costs
    - Firm Fuel Supply Costs
    - Book Life
    - Fixed O&M
    - Variable O&M
    - Heat Rate Curves
    - Forced Outage Rates
    - Typical Annual Maintenance Requirements
    - CO_2 Emission Rate
    - NOX Emission Rate
    - SO_2 Emission Rate
    - PPA Pricing if applicable

Output Information

- Annual System Peak
- Annual System Capacity Obligation
- Total System Capacity
- Capacity Additions (Expansion Plans)
- Capacity Retirements
- System Capacity Mix Aggregated Into the Following Categories
    - Load Management
    - Coal
    - Carbon Free Baseload
    - Biomass
    - Gas Combined Cycle

  - Gas Combustion Turbine
  - Oil
  - Hydro
  - Pumped Storage
  - Wind
  - Solar
  - Geothermal
  - System Purchases / Sales
  - SPS Interchange
- System Emissions
  - CO_2
  - SO_2
  - NOx
  - PM
  - Mercury
- System Fuel Burn
  - Natural Gas
  - Coal
  - Oil
- Revenue Requirements for Capital Projects (not all Public Service capital projects are modeled) Aggregated Into the Following Categories
  - Coal
  - Carbon Free Baseload
  - Biomass
  - Gas Combined Cycle
  - Gas Combustion Turbine
  - Oil
  - Hydro
  - Pumped Storage
  - Wind
  - Solar
  - Geothermal
- Fixed Costs Including Fixed O&M and PPA Capacity Payments Aggregated Into the Following Categories
  - Coal
  - Carbon Free Baseload
  - Biomass
  - Gas Combined Cycle
  - Gas Combustion Turbine
  - Oil
  - Hydro
  - Pumped Storage
  - Wind

        - Solar
        - Geothermal
        - Capacity Credits
- Energy Costs Including Fuel, Variable O&M, and Energy Payments Aggregated Into the Following Categories
    - Coal
    - Carbon Free Baseload
    - Biomass
    - Gas Combined Cycle
    - Gas Combustion Turbine
    - Oil
    - Hydro
    - Pumped Storage
    - Wind
    - Solar
    - Geothermal
    - Short-term Energy Purchases
- Total Emission Costs
    - CO_2
    - NOX
    - SO_2
    - PM
    - Mercury
- Total PVM Costs
- Total Wind Integration Costs
- Total Wind Related Coal Cycling Costs
- Total Wind Curtailment Costs
- Total DSM Costs

Concerning the Strategist model that the Company used to represent the Public Service system,[26] the model has millions of discrete data points that it uses to represent the Public Service system. The model is very much an organic model whose inputs are not in discrete files that can be provided or that would be easily understood or manipulated. Specific questions concerning Strategist inputs will likely receive a specific and useful response. Public Service cautions that the Company cannot answer all non-specific Strategist input questions. An example of a non-specific question would be: "Provide all Strategist input files," or "Provide all Strategist input files and assumptions." There are no such files and the assumptions are too numerous to list in a productive manner.

[26] The model was used to produce alternative plans for the Phase 1 filing and will be used to evaluate the bids in a solicitation.

Confidential Information

Public Service will seek to protect the following proprietary information as confidential information:

Strategist Model Data

Input Information

- Hourly Load Patterns
- DSM Hourly Patterns
- Monthly On/Off Peak Market Prices
- Market Emission Assumptions
- Market Import Constraints
- Unit Seasonal Deration Profiles
- Unit Variable O&M
- Unit Fixed O&M
- System Annual Fixed Gas Delivery Charges
- Unit Average Maintenance Requirements
- Unit Average Forced Outage Rate
- Unit Contribution to Spinning Reserve
- Unit Emission Rates
    - SO_2
    - NOX
    - CO_2
    - PM
    - Mercury
- PPA Capacity Pricing (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Energy Pricing (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Energy Schedules (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Contribution to Spinning Reserves
- PPA Seasonal Capacity Derate Profiles
- PPA Emission Rates
    - CO_2
    - SO_2
    - NOX
    - PM
    - Mercury
- Hourly Wind Patterns
- Hourly Solar Patterns

Output Information

- Unit Level Maximum Capacity
- Unit Level Summer Accredited Capacity
- Unit Level Generation
- Unit Level Capacity Factors
- Unit Level Fuel Consumed
- Unit Level Average Heat Rate
- Unit Level Total Variable O&M
- Unit Level Fixed O&M
- DSM Hourly Patterns
- Unit Level Capital Expenditures (note not all Public Service capital expenditures are modeled)
- Unit Level Rate Base (note rate base not modeled for all Public Service units)
- Unit Level Revenue Requirements (note revenue requirements not modeled for all Public Service units)
- Unit Level Emissions
    - NOx
    - SO_2
    - CO_2
    - PM
    - Mercury
- PPA Maximum Capacities
- PPA Summer Accredited Capacities
- PPA Generation
- PPA Capacity Factors
- PPA Total Energy Payments (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Total Capacity Payments (to the extent the counter party agrees to allow contract terms to be divulged)
- PPA Emissions
    - NOx
    - SO_2
    - CO_2
    - PM
    - Mercury

Highly Confidential Information

Public Service will seek to protect the following proprietary information as highly confidential information:

- Unit Level Delivered Fuel Costs
- Hourly Market Price Data
- Unit Level Heat Rate Curves

- Unit Detailed Maintenance Schedules
- Bid Information of any Sort (from the Company and from other entities)
- Any information protected by confidentiality clause of a PPA
- Strategist Files[27]

Public Service believes that disclosure of the items listed above can cause irreparable harm to the Company's trading operations, the Company's ability to solicit cost-effective resources and, ultimately, the Company's customers. The Company will seek to limit access to the Independent Evaluator, the Office of Consumer Counsel and the Commission Staff.

<u>Information that Public Service will Provide Bidders</u>

Public Service will provide the following Public Service developed information to bidders with respect to their own bids after initial bid screening and before Strategist modeling:

- Levelized Cost of Energy
- Transmission Interconnection Costs
- Gas Supply Costs
- Wind Integration Costs
- Benefit of Geographic Diversity of Wind Generation Resource
- Benefit of Energy Storage Resource

<u>Protection of Bid Information, Modeling Inputs and Assumptions, and Bid Evaluation Results</u>

Public Service will seek to protect all bid information and bid evaluation results (including Company self-build proposals) that would reveal specific bid pricing or other bid information, as highly confidential information in accordance with the Commission's rules, until completion of the resource acquisition process, i.e. until the last contract for a resource that meets a portion of the 2011 ERP resource need is signed. Upon completion of the resource acquisition process, Public Service will post on its website the following bid information:

- Bidder Name
- Bid Price (Utility Cost for Utility–Owned Proposals)
- Generation Technology Type
- Size of Facility
- Contract Duration (Expected Useful Life of Utility Resource)
- Purchase Option Details as relevant

[27] Public Service can only provide Strategist Files to Intervenors that hold a Strategist License

In accord with the proposed ERP Rule 3613(j) within fourteen months after completion of the resource acquisition process, Public Service will make public confidential information that was redacted from Public Service's testimony and reports by re-filing the testimony or report in an un-redacted form.

If any Public Service highly confidential modeling inputs and assumptions, listed above under highly confidential information, are entered into the record in any manner, Public Service will seek to indefinitely continue the protection ordered by the Commission.