Public Service Company of Colorado

2016 Electric Resource Plan
Volume 1

(CPUC Proceeding No. 16A-0396E)
May 27, 2016

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1.0 EXECUTIVE SUMMARY

Public Service Company's proposed 2016 Electric Resource Plan ("2016 ERP") is designed to reflect and accommodate the current energy market while providing a path to acquire the necessary generation resources to meet future capacity and energy needs of the system. The 2016 ERP proposes using a competitive acquisition process to fill the future capacity and energy needs of the system over an 8-year Resource Acquisition Period ("RAP") through 2023, thus aligning the acquisition window of this ERP with the timing of the next resource plan that is expected to be filed in 2019. Public Service is interested in participating in the ownership of generation resources that may be offered and/or selected in conjunction with the proposed Phase II process or possibly offered as a separate ownership proposal. Similar to the circumstances the Company described in the 2011 ERP, today's energy market is in a state of flux and uncertainty. In addition, with lower natural gas prices, the extension of federal tax credits, surplus existing thermal generation, and improvements in generation technology, the energy markets are more competitive today than they have ever been in recent years. While the Company's initial modeling suggests that the addition of low cost gas fired peaking capacity alone could provide a cost-effective solution for filling the capacity needs of the system, the addition of low cost wind and solar resources along with gas can provide further savings to customers, while also providing a hedge against future carbon regulation and natural gas price volatility.

When looking towards the resource acquisition process in Phase II of this proceeding, Public Service has provided a pathway conducive to adding more wind and solar resources. As a result of Public Service's leadership over the last ten years in developing a portfolio of renewable resources that is ahead of schedule in complying with the state's Renewable Energy Standard, Public Service can now plan for and acquire additional sources of renewable energy to the degree that they bring cost savings to our customers. As a result of these dynamics and the interchangeability of combustion turbine capacity and incremental wind and solar resources, the 2016 ERP does not prescribe specific generation resources to be acquired, but instead provides a path and process forward (through 2023) that recognizes the transition from our current generation fleet to one that includes more distributed energy resources and customer choice along with increased levels of renewable energy resources.

The 2016 ERP is designed to acquire the approximate 615 MW of additional generation capacity resources that are expected to be needed through 2023, based on the Company's December 2015 Demand and Energy Forecast.

Building on the circumstances and issues identified in the 2011 ERP, the Company's projection of need for additional generation resources is being influenced by a number of factors that have resulted in a greater level of uncertainty in these projections than in prior ERPs. While there has always been uncertainty as to the economic expectations included in the Company's forecast of electric demand and energy over the years, Public Service is now facing a convergence of issues associated with an energy market that is in transition. The following summary lists some of the near-term issues that have the potential to affect the customer electric demand, and thus affect the resource need to be filled in this ERP:

1. Increasing levels of distributed generation;
2. Increased customer participation in customer choice programs including Community Solar Gardens and expected participation in the Company's proposed Solar*Connect program;
3. Utilization of more energy efficient appliances and lighting;
4. Significantly lower oil and natural gas prices resulting in a downturn in the energy sector and a lower energy and demand forecast for these oil and gas companies;
5. Reduced peak electric demand associated with the Company's proposed future filing for components of the "Advanced Grid Intelligence and Security" ("AGIS") initiative; and,
6. The potential impact of future tariff and service changes as our customers' energy options continue to evolve.

As with past ERP processes, the Company is presenting an initial demand and energy forecast in the 2016 ERP that was available at the time the ERP was being developed. During Phase I and at the beginning of the competitive acquisition phase (Phase II) of this planning process, the Company plans to update its demand and energy forecasts to capture the impacts of these changing dynamics in the energy markets before the actual resources are selected.

In addition to the issues affecting customer demand, there are a number of factors that will influence the mix and timing of supply-side generation resources that will ultimately be acquired to satisfy the identified needs of the system. Colorado is uniquely located in one of the best energy rich zones in the country. We are located in one of the best wind zones in the country, we sit near vast reserves of low cost coal, there is an abundance of natural gas production in the state and in nearby states, and our solar resource is in the top ten of the country. As a result of our location and access to some of the best energy resources in the country we are seeing more competition between the different generation technologies than we have seen in the recent years. The following is a list of factors that make this resource planning process somewhat unique due to this increased competition between generation technologies:

- Historic low natural gas prices;
- Underutilized natural gas generation facilities in the region;
- Extension of the Production Tax Credit ("PTC") for wind;

- Extension of the Investment Tax Credit ("ITC") for solar;
- A downward sloping cost curve for solar generation;
- Enhancements to the distribution grid allowing for new related services; and,
- Delay of the proposed Clean Power Plan.

As a result of these factors, we expect to see competitive pricing offered from the market between all types of generation resources during the proposed 8-year RAP. From our modeling of alternative plans, low cost wind resources tend to be picked in all scenarios. Following wind, low cost solar that provides more of a balance of energy and capacity is also picked in the various scenarios. Natural gas-fired peaking capacity, primarily the larger combustion turbines, are generally the resources that fill in the remaining capacity needs of the system while also providing added flexibility to help manage the variable nature of renewables. To capture the benefits of this competitive environment, Public Service is proposing a competitive acquisition process for Phase II to acquire the necessary resources in which all generation technologies will be considered.

The final set of issues that have the potential to impact this 2016 ERP include the various proceedings that are currently underway or are expected to be filed in the near future. The following is a list of these various proceedings:

Topic/Proceeding Number
2017 RE Plan (Proceeding No. 16A-0139E)
Solar*Connect Program (Proceeding No. 16A-0055E)
Rush Creek Wind Project (Proceeding No. 16A-0117E)
Proposed AGIS System (N/A – not yet filed)

While the Company is forecasting a capacity need of approximately 615 MW by 2023, the outcome of these various regulatory proceedings could significantly impact the overall capacity and energy need of the system over the RAP. To the extent these proceedings are finalized by the beginning of the Phase II competitive acquisition process or the actual results of these programs differ from the assumptions underlying the Company's forecasts, Public's Service estimates that its actual capacity need in 2023 could range from as low as approximately 200 MW to as high as approximately 800 MW. Due to this higher degree of uncertainty, Public Service is proposing to wait until the beginning of the Phase II acquisition process to finalize the determination of resource need to be acquired in this ERP.

Regarding potential carbon regulation and the proposed Clean Power Plan ("CPP"), the recent U.S. Supreme Court stay of the CPP adds to the uncertainty the Company faces in this 2016 ERP. The proposed 8-year RAP includes years 2022 and 2023, the first years of the proposed plan rule. Absent the details that a final federal rule and state CPP compliance plan for Colorado would provide, the Company's ability to provide a substantive discussion on this issue in this ERP is limited. In addition, without knowing the specific details of a possible State Compliance Plan, the Company is not in a position of suggesting additional plant retirements. Nevertheless, the Company believes that our continued efforts in the area of DSM and customer choice programs, coupled with our plan to add the Rush Creek Wind Project under Rule 3660(h), and possibly additional wind and solar through this ERP, will further enhance the Company's position to address future public policy regulations regarding carbon.

In summary, while the changing dynamics of today's energy market makes it challenging to lay out a very detailed plan for the RAP, the abundant availability of low cost natural gas, wind, and solar resources provides the opportunity for customers to lock-in a low risk and low cost solution for a number of years to come.

1.1 INTRODUCTION AND BACKGROUND

Purpose of Filing

Public Service Company of Colorado ("Public Service") submits this 2016 Electric Resource Plan ("2016 ERP") pursuant to the Electric Resource Planning Rules, 4 CCR, 723-3-3600 *et. seq.* ("ERP Rules"). The 2016 ERP provides the framework for how the Company assesses the need for future electric supply resources over the specified 8-year RAP from May 2016 through May 2024, as well as a plan for acquiring those resources.

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

Contents and Organization of the 2016 ERP

The 2016 ERP filing is comprised of the following three volumes:

Volume 1: 2016 ERP

Volume 2: Technical Appendix and References

Volume 3: Requests for Proposals and Model Agreements

Volume 1 of the 2016 ERP contains the Company's assessment of need for additional resources and the Company's proposed plan for meeting that need. Also included are descriptions of how the alternative plans were developed and analyzed.

Volume 2 provides technical information consistent with the requirements of the ERP Rules, including detailed information about the Company's power supply resources and sales forecasts as well as other references.

Volume 3 contains the requests for proposals ("RFP") and the model agreements that will be used to acquire generation resources.

Procedural Background

On June 17, 2015, Public Service filed a Petition (Proceeding No. 15V-0473E) to seek a waiver of the October 31, 2015 deadline to file its next ERP and Renewable Energy Standard ("RES") Compliance Plan as required by Rules 3603 and 3657 of the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* 723-3.

The request for a delayed ERP filing was based on the benefit of additional time to understand Colorado's approach to complying with the final Clean Power Plan ("CPP") rules for carbon dioxide emissions from existing power plants recently issued by the Environmental Protection Agency ("EPA") under Section 111(d) of the Clean Air Act. Public Service proposed to bifurcate its next RES Compliance Plan filing from the ERP filing and to file the separate RES Compliance Plan not later than February 29, 2016.

On August 21, 2015 in Decision No. C15-0925, the Commission granted Public Service's request to delay the filing of its next ERP beyond October 31, 2015 and required Public Service to file its ERP and RES Plan no later than February 29, 2016. Additionally, the Commission directed Public Service to file an ERP annual progress report on or before October 31, 2015 with an update on the projected impact of the final CPP rules.

On January 26, 2016, Public Service filed a motion for waiver and variance of the requirement in Decision No. C15-0925 that it file an ERP no later than February 29, 2016 and requested a three month extension of the filing deadline to no later than June 1, 2016. Public Service requested this three-month extension: (1) to allow more time to perform a detailed physical and economic analysis of the potential to add up to 1 gigawatt of renewable resources to its system; and (2) to allow more time to fully develop a resource plan that takes into account the PTC and ITC that were extended on December 18, 2015 as part of the Omnibus Appropriations Act ("Act") that was signed into law by President Obama.

On February 16, 2016, the Commission issued Decision No. C16-0127 in Proceeding No. 15V-0473E and allowed the bifurcation of the Company's ERP and the 2017 RE Plan and granted the three-month extension to file the ERP no later than June 1, 2016. While allowing the bifurcation of these filings, the Commission noted that select Rules "specify that the Commission use certain information or assumptions from the Company's most recently approved ERP in its evaluation of the 2017 RE Plan." Because the 2017 RE Plan would be filed on February 29, 2016, prior to the filing of the 2016 ERP, the Commission required Public Service to "file the required assumptions concurrent with its 2017 Renewable Energy Plan ('RE Plan') application filed not later than February 29, 2016."

On February 29, 2016, Public Service filed, in new Proceeding No. 16A-0138E, a summary of updated technical inputs and assumptions (also referred to as “modeling assumptions”) based on those provided in Attachment 2.8-1 in Volume II of Public Service’s 2011 ERP and then updated in April 2013 prior to the 2013 Phase II All-Source Solicitation. The updated assumptions (used in the 2017 RE Plan analysis) were included as Attachment A to the Company’s February 29, 2016 filing.

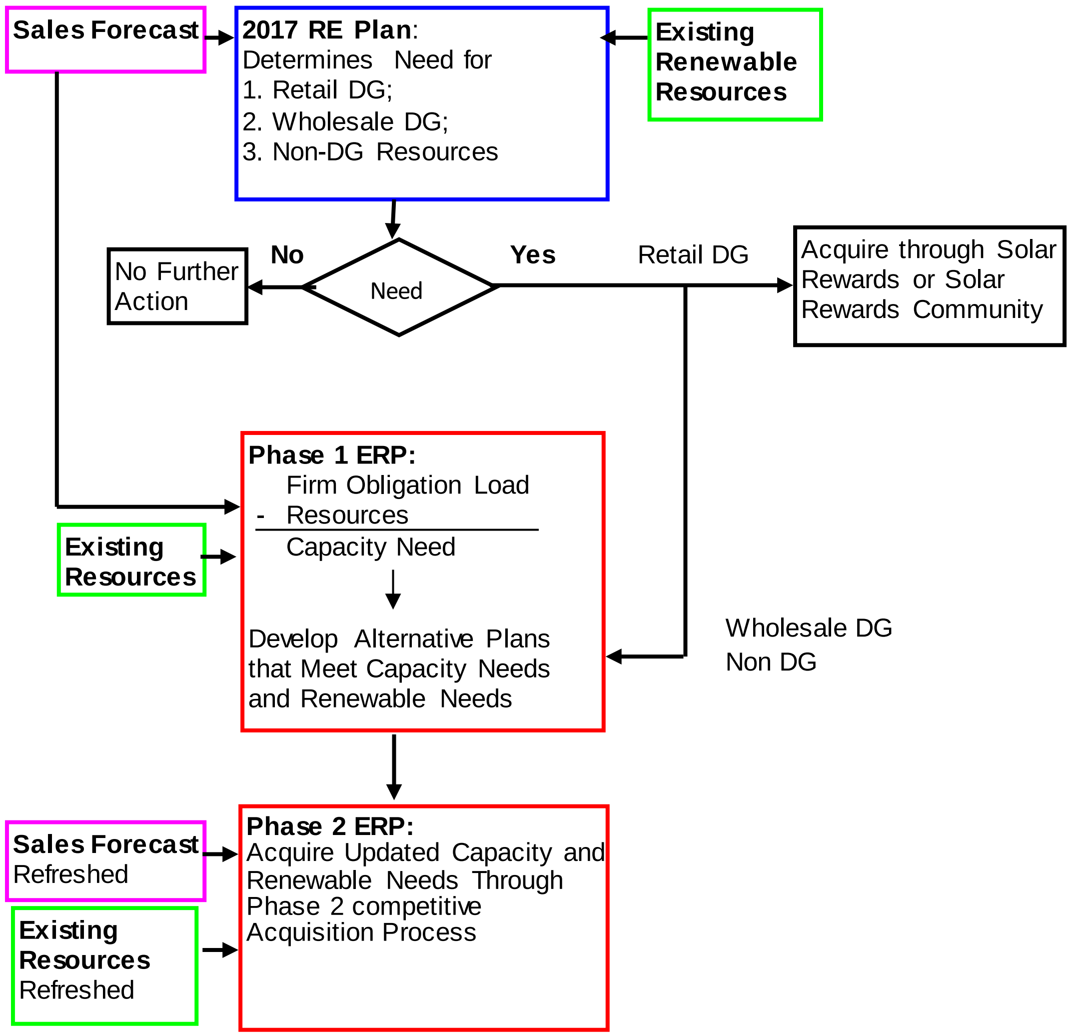
High Level 2016 ERP Process Overview

A high level overview of the ERP process, including how the 2017 RE Plan will inform the ERP assessment of need for additional resources and how that need is met with resources acquired in Phase II, is illustrated in Figure 1.1-1.

Public Service’s 2017 RE 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 or Solar Gardens Programs

Figure 1.1-1 High Level 2016 ERP Process Overview



Summary and Status Update of 2011 ERP

Public Service filed its 2011 Electric Resource Plan ("ERP") on October 31, 2011 with the Commission in Proceeding No. 11A-869E. In Decision Nos. C13-1267 and C13-1566, the Commission approved the Company's preferred portfolio of incremental generation resources identified in the 2013 All-Source Solicitation. These resources and the current status of their procurement are summarized in the Table below:

Table 1.1-1 2013 All-Source Solicitation Resources and Procurement Status

Resource	Fuel Type	Capacity (MW)	PPA Term (Years)	Contract Start Date
Fountain Valley	Gas	238	18	2/1/2014
Brush 1/3	Gas	76	8	5/1//2017
Limon III	Wind	200	25	10/2/2014
Golden West	Wind	250	25	10/12/2015
Comanche	Solar	120	25	Q2 2016
Hooper	Solar	50	20	Q4 2016
Cherokee Unit 4	Gas	352	continued	1/1/2018

In addition to generation changes resulting from the 2011 ERP, the Company's Cherokee Units 5, 6, 7 (a 2 x 1 natural-gas fired, combined cycle facility) entered service on August 20, 2015. The Company's 45 MW Arapahoe Unit 3 and the 111 MW Unit 4 were retired on December 20, 2013. The Company's Cherokee Unit 3, a 152 MW coal-fired unit, was retired from service on August 20, 2015.

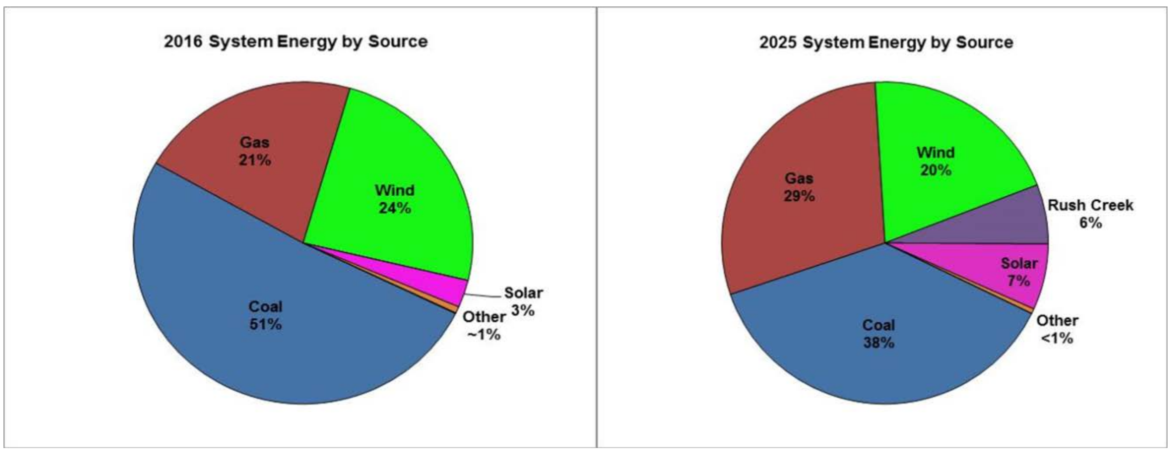
1.2 LANDSCAPE

Public Service System Energy Mix

Each year, the Public Service electric power supply system serves the approximate 32,000,000 MWh energy needs of our customers with a diverse mix of generation technologies and fuel sources. The Company continues to be a leader in the area of acquiring renewable energy resources and has been the number one provider of wind energy in the country for the past 12 years.

Figure 1.2-1 provides an illustration of the Company's current energy mix in 2016 alongside a projection of how that mix will change by year 2025.

Figure 1.2-1 Projected System Energy Mix in 2016 and 2025



As indicated in Figure 1.2-1, in 2016 roughly 50% of the generation on the Public Service system is projected to come from coal fired sources, with more than 25% coming from renewable sources (solar and wind), and the bulk of the remainder coming from natural gas resources. Further, the Company's proposed development of the 600 MW Rush Creek Wind Project and high levels of customer choice solar has a substantial impact on the overall system energy mix by 2025.

- Coal generation is expected to drop by ~13% from 2016 levels, comprising less than 40% of the overall generation by 2025.
- Generation from all renewable sources (wind and solar) is expected to make up ~33% of the total. Notably, Rush Creek is expected to produce ~6% of total generation.

- Generation from gas resources is also expected to significantly expand, comprising just under 30% of the total.

This significant change in the system energy mix provides insight into the mechanics by which the Company's projected reduction in overall CO_2 emissions are realized.

Figure 1.2-2 Public Service CO_2 Reduction by Source

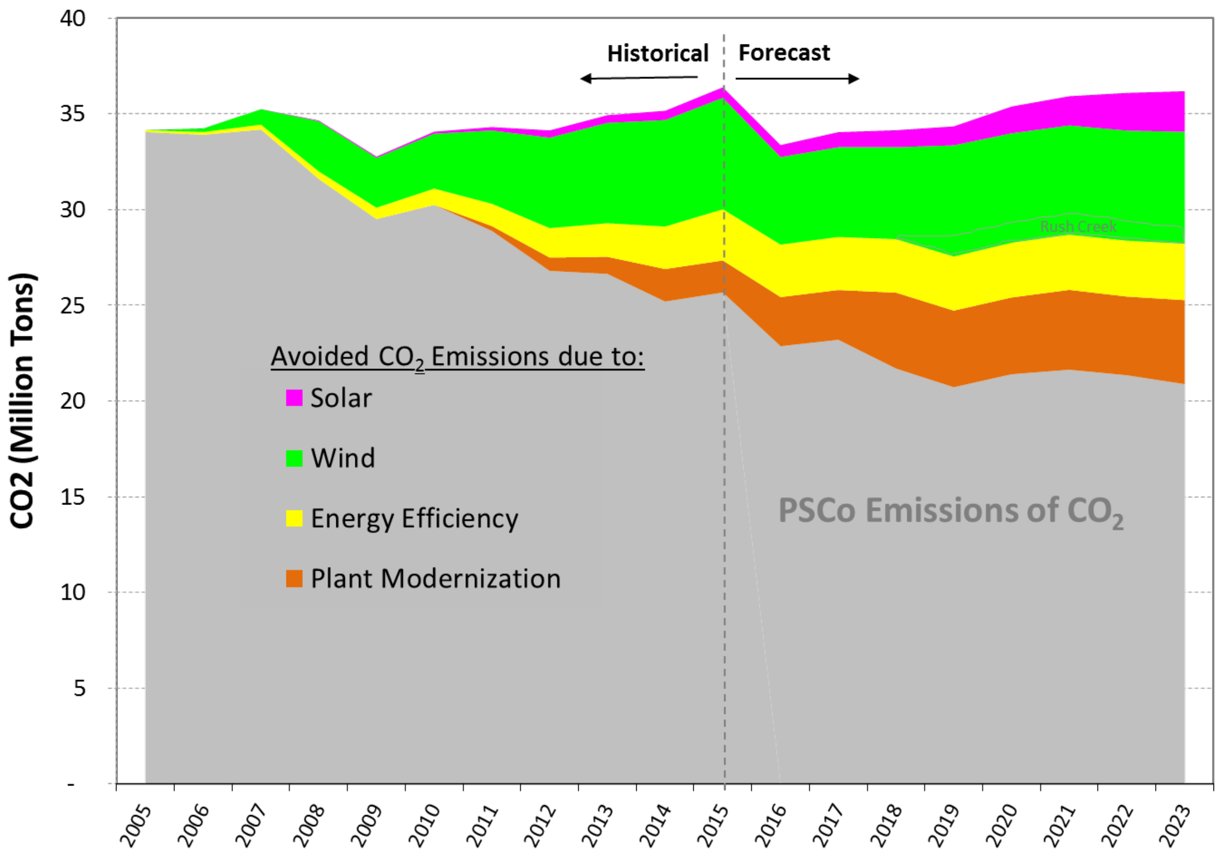


Figure 1.2-2 details the reductions in CO_2 emissions on the Public Service system from both historical and planned actions. Overall, system CO_2 emissions decreased from a total of ~34 million tons in 2005 to ~26 million tons in 2015. System emissions are projected to drop even further to a level of ~23 million tons in 2016 (primarily due to the retirement of the Cherokee 3 coal plant in late 2015 and a full year of operations for the new Cherokee 567 combined cycle facility in 2016).

As outlined above, by the end of 2016 total emissions reductions achieved by Public Service programs will total ~11 million tons relative to 2005 levels (a total reduction of ~33%.) A breakdown of the avoided emissions by program in 2016 is provided in Table 1.2-2.

Table 1.2-1 Percent of 2016 Emissions Avoided by Source

Source	2016 CO_2 Avoided Emissions (% of Total Avoided Emissions)
Solar	6%
Wind	44%
Energy Efficiency	26%
Plant Modernization (1)	24%
(1) Includes actions under Clean Air- Clean Jobs	

As shown in Table 1.2-1, through 2016 the largest source of avoided emissions on the Public Service system is due to the Company's wind portfolio, with significant contributions from the other categories.

By 2023 (the end of the proposed RAP period), due to the anticipated addition of the Rush Creek wind facility, additional coal retirements, aggressive solar additions, and continued energy efficiency, total avoided CO_2 emissions are expected to total ~15 million tons. A breakdown of the avoided emissions by source in 2023 is provided in Table 1.2-2.

Table 1.2-2 Percent of 2023 Emissions Avoided by Source

Source	2023 CO_2 Avoided Emissions (% of Total Avoided Emissions)
Solar	14%
Wind (non-Rush Creek)	30%
Rush Creek	7%
Energy Efficiency	20%
Plant Modernization (1)	29%
(1) Includes actions under Clean Air- Clean Jobs	

As shown in Table 1.2-2, the contribution to overall avoided emissions from solar generation grows significantly from 2016 – 2023. In addition, the 600 MW Rush Creek Wind Project is expected to avoid approximately 1 million tons of CO_2 each year, representing more than 6% of total avoided CO_2 emissions.

Energy Markets in Transition

The transition of Colorado's electric generation market began in earnest approximately 10 years ago. In 2004, Public Service started down a road that would forever change the Company's generation strategy and portfolio. Since 2004, the Company has added approximately 2,600 MW of wind generation and will produce approximately 24% of its energy from wind in 2016. In addition to the significant additions of wind generation, the Company has proposed to significantly increase the use of solar generation, distributed generation and customer participation in their individual energy decisions. This dramatic shift in generation strategy over the last ten years mirrors the changes in the energy industry happening throughout the country.

One of the key drivers in this transition was the need to comply with the minimum percentage requirements of the state's RES. The RES requires Public Service to generate a minimum of 30 percent of its energy from qualified renewable energy resources by 2020. The Company uses the Renewable Energy Credits ("REC") generated by these renewable resources to satisfy the minimum annual requirements of the RES. Due to the progressive direction taken by the Company in regards to renewable energy, the Company has an ample supply of RECs to satisfy the compliance of the RES through 2030. As a result, the desire to acquire more renewable energy in this plan is driven by the economic value of the renewable energy, as opposed to the strict need to comply with the minimum requirements of the RES.

In addition to the migration towards more renewable resources, the desire of our customers to participate more in their energy futures, along with the improvements in distributed generation technologies, has created an environment that includes significantly more uncertainty when it comes to determining the need for generation resources and the type of resource to be acquired. The following sections provide more detail as to the specific issues and impacts the Company faces in the resource planning process and how these issues can significantly impact the need for future generation resources.

Increasing levels of distributed generation (Solar*Rewards and Solar*Rewards Community)

Public Service's Solar*Rewards program has been very successful in creating a distributed generation program in the state. Over the last 5 years, the Company has averaged installations of approximately 36 MW of rooftop solar each year. In the 2017 RE Plan, the Company is proposing to increase this opportunity to approximately 90 MW per year for the years 2017 through 2019. After 2019, the Company has included a placeholder of the same approximate 105 MW per year in its planning models for additional customer choice solar. The overall net impact of the Company's 2017 RE Plan filing and the placeholder we have included in the 2016 ERP is a decrease in total need of approximately 215 MW through 2023. To the extent the implementation of this program deviates from the capacity quantities listed above, the Company could end up either long (i.e., having additional generation resources) or short on resources. In the latter case, the Company could face a situation where it may need to acquire extra resources.

The Company's proposed Solar*Connect program

In addition to the distributed generation programs described above, the Company has proposed the Solar*Connect product offering for customers who may want solar, but do not want to or cannot install solar on their roof. The Solar Connect program proposes to acquire 50 MW of solar (approximately 15-20 MW of accredited capacity). In total, the combination of the distributed generation and Solar*Connect programs have the effect of lowering overall capacity needs by approximately 230 MW over the RAP. Again, to the extent these programs are not approved or are not implemented as planned, the Company could end up with a surplus or deficit of generation capacity over the RAP.

Utilization of more energy efficient appliances and lighting

Technology and utilization of various appliances such as televisions, computers, phones, and lighting has resulted in lower energy consumption over the past several years. This trend of reduced energy consumption is expected to continue. As a result, this naturally occurring Demand Side Management ("DSM") has been suppressing the need for additional generation. To the extent this naturally occurring DSM continues but at a slower or faster pace than what is included in the ERP, the Company again could be short on generation resources or face a pressing need to acquire resources in excess of what may be needed.

Significantly lower oil and natural gas prices

The December load forecast (used in the Phase I ERP analysis) anticipated that an additional ~200 MW of increased generation load from the oil and gas sector would be added by 2021. Due to the recent weakness in oil and natural gas prices, we now anticipate this incremental demand will not fully materialize until 2024. To the extent this load does not materialize or materializes on a different schedule than what we have included in the ERP, the Company will have to take the steps necessary to ensure the system will have adequate resource coverage.

Reduced peak electric demand associated with the Company's proposed future filing for the "Advanced Grid Intelligence and Security ("AGIS") and the related tariff and services changes

To facilitate the opportunity to deploy additional distributed generation resources, the Company is expecting to propose a plan to modernize the existing distribution gird. The AGIS project will install the equipment necessary for the Company to receive real time distribution and metering data, provide the opportunity to offer more distributed generation, and provide the framework that will allow the Company to offer customers new tariff services such as Time-of-Use Rates. From the initial work on this project, the Company is anticipating these modifications and enhancements to the existing grid and services may reduce the overall peak day capacity requirements of the system in the range of 100 MW to 300 MW over the RAP.

In summary, the utility focused energy markets are undergoing significant transition. While it is difficult to predict exactly the speed and magnitude of these changes, these issues and opportunities will certainly impact the overall needs of the system and the type of resources that best fit those system needs.

Energy Market Dynamics and External Factors

In addition to the more customer focused transition issues and opportunities, the dynamics of the overall energy market are in a state of flux. Natural gas prices, changing generation technologies, environmental regulations, federal tax credits and other subsidies can have a significant impact on the overall generation and portfolio strategy. The following subsections are a more detailed discussion on these broader market issues.

Low Natural Gas and Oil Prices

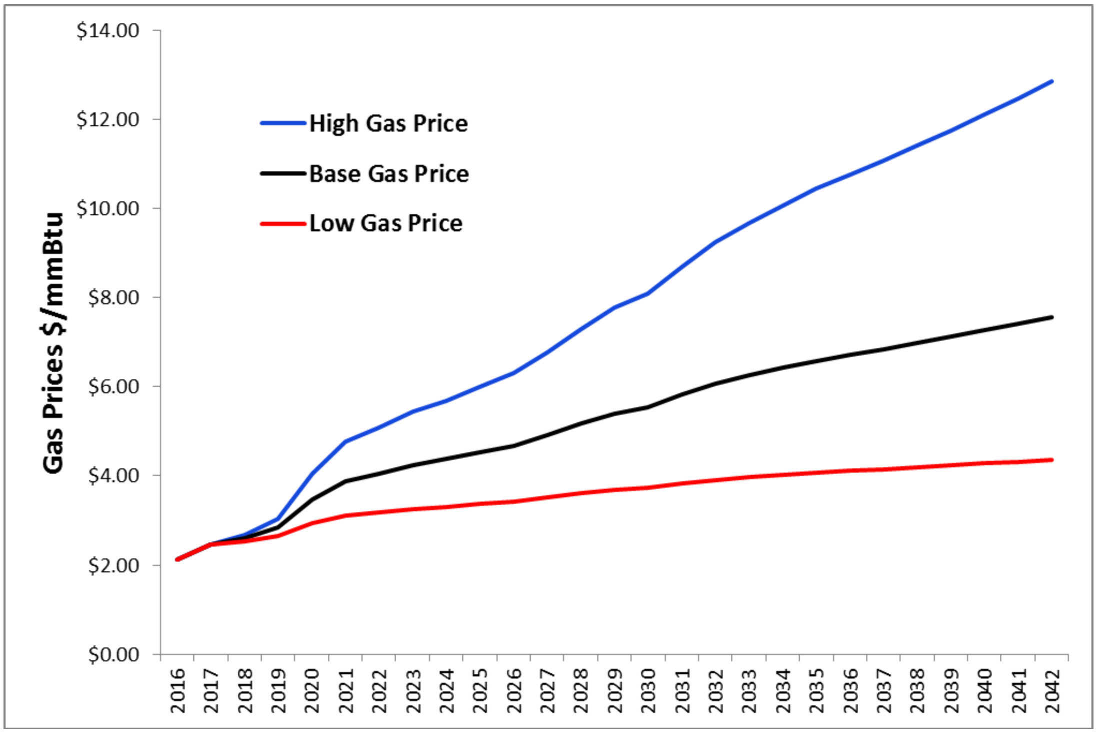
The market fundamentals for natural gas have changed dramatically over the past few years. In 2016, the natural gas futures markets reached lows not seen since the late 1990s. These lows have been driven by a combination of increased production, high inventory levels and mild weather. All of these issues have forced the gas market to price competitively with coal to increase demand in order to balance the market.

This low price natural gas environment, combined with low oil prices, has put significant financial strain on producers and a number of them have filed bankruptcy as their ability to access the capital markets has become constrained. This financial stress has forced producers to become very innovative by reducing rig counts, improving drilling efficiency, controlling costs and focusing on their most productive drilling locations.

It is projected that natural gas prices have bottomed out for the foreseeable future and will start to push back towards the $2.50 to $3.00 level (absent a significant weather event). Over the longer term natural gas prices are expected to rise gradually as producers will have already drilled their most productive locations and supply and demand balances out. However, natural gas markets have been extremely fickle over the years and the low prices that are in the current forecasts may or may not materialize. Factors that could impact the current price forecasts include:

1) Increased demand driven by one or more of the following; LNG exports, exports to Mexico, industrial demand and/or stronger economic growth;
2) Increased regulation such as the Clean Power Plan, which could increase demand from gas fired generation and/or other regulations that further reduce coal fired generation;
3) A lag in rig deployments and crew mobilizations as demand for drilling rigs rebounds; and
4) Access to capital markets.

Figure 1.2-3 2016 ERP Gas Price Forecast



As indicated in Figure 1.2-3, the gas forecast utilized in the 2016 ERP Phase I analysis reflects continued low gas prices for the next several years with prices below $4 (nominal) through 2021 with relatively slow growth in the medium to long term.

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.

Federal Tax Credit Extensions

On December 18, 2015, President Obama signed into law the Act providing extensions of the PTC and ITC. Prior to the passage of the Act, the PTC had expired and the ITC was set to decline at the end of 2016.

Production Tax Credit - Wind

The Act included a five-year extension of the PTC for wind and other eligible renewable energy projects. While the PTC has been extended for five years through the end of 2019, it declines in the final three years after December 31, 2016 (i.e., 80% of its current level in 2017, 60% in 2018, and 40% in 2019).

On May 5, 2016 the IRS updated its safe harbor guidance. Eligible projects that meet IRS safe harbor requirements for beginning construction, i.e., expenditures of 5 percent of the total project cost by December 31, 2016 and in service by December 31, 2020, will qualify for the 2016 PTC level of 100 percent. The revised safe harbor guidance defines the "begin construction" standard the same as past guidance, but extends the deadline for "continuous construction" requirements. Specifically, rather than the facility needing to be in service two years after beginning construction, the IRS has extended that requirement to four years. Thus, the deadline for the in service date of the facility in order to qualify for the PTC at 100 percent has been changed from year end 2018 to year end 2020.

Investment Tax Credit - Solar

The current 30% solar ITC was extended through 2019 and reduced to 26% in 2020 and 22% in 2021. The law includes language allowing two additional years to complete projects under construction on January 1, 2022. The Company is still awaiting clarification from the IRS regarding the details of related safe harbor provisions.

Clean Power Plan and Carbon Regulation Policy

In early August 2015, the U.S. Environmental Protection Agency finalized the Clean Power Plan to regulate carbon dioxide emissions from the nation's existing power plants. The rule seeks to reduce emissions of carbon dioxide, a greenhouse gas, from most major existing power plants in the U.S.

After the rule was finalized, 27 states and a number of industry groups filed legal challenges. All of the cases against the rule were consolidated into one case before the U.S. Court of Appeals for the D.C. Circuit. Some of the states challenging the rule also asked the court to stay implementation until legal issues were decided. In January 2016, the D.C. Circuit Court decided that the rule should remain in effect while it considers the merits of the legal challenge. The plaintiffs subsequently asked the Supreme Court to stay implementation of the rule. In early February 2016, the Supreme Court decided to stay the CPP pending final resolution of the issue by the U.S. Supreme Court (i.e., either a ruling on the merits or a denial of a petition for writ of certiorari). The D.C. Circuit Court has now scheduled oral arguments before its full panel on September 27, 2016.

This stay adds more uncertainty to the rule, creating up to two years of delay. A decision from the D.C. Circuit Court is not expected until late 2016 at the earliest, following oral arguments. This means the Supreme Court could hear the case sometime in the fall of 2017 or spring of 2018, depending on when the D.C. Circuit issues its decision. The potential outcomes include the rule being upheld, the rule being struck down, or the rule being upheld in part and vacated in part, among other potential outcomes. No matter what the courts ultimately decide, we believe that U.S. or state-level climate policy remains a strong likelihood for the industry, although the CPP's future is now more uncertain.

The legal uncertainties around the rule also create uncertainties for the original deadlines of the CPP. The first deadline for an initial state plan submission in September 2016 is now invalid. The next major deadline, for a final state plan submission to EPA in September 2018, is uncertain. Also uncertain is the beginning of the compliance program in 2022 as set forth in the final rule. If the rule is upheld, we expect new information on these deadlines, and it is likely – though not guaranteed - these deadlines will change. The Colorado Department of Public Health and Environment is continuing work on a potential state plan, and most Colorado utilities, including Public Service, are participating in that process.

Other Environmental Regulatory Challenges

Electric utilities must comply with an array of federal and state environmental regulations that govern the construction of new generating plants and the operation of existing facilities. The following summarizes the major environmental regulatory programs that currently affect or have the potential to affect Public Service.

Regional Haze

In January 2011, the Colorado Air Quality Control Commission ("AQCC") completed a rulemaking process to meet the requirements of the Federal Regional Haze Rule to improve the visibility in Class I areas, such as National Parks and Wilderness Areas, across the country. The Regional Haze Rule includes Best Available Retrofit Technology ("BART") requirements for units built between 1962 and 1977. The Public Service units subject to BART include Hayden 1 and 2, Comanche 1 and 2, Cherokee 4, Valmont 5, Pawnee 1, and the Public Service portion of Craig Units 1 and 2. The Colorado Air Pollution Control Division developed a State Implementation Plan ("SIP") for the 12 regulated Class I areas in the state that identify the sources contributing to visibility impairment and establish control measures to improve visibility. This SIP required emission reductions of sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") for all BART units along with other non-BART electric generating units and non-utility sources such as cement kilns and industrial boilers. The Regional Haze SIP was approved by the Environmental Protection Agency ("EPA") Region 8 in December 2012. The Regional Haze SIP incorporated the provisions of the Clean Air-Clean Jobs Act as described below. Regional Haze is an ongoing program that will require updated plans at 5 year intervals to show reasonable progress towards improving visibility in Class I areas. The next planning period is currently set for 2018 but EPA has proposed to extend that planning period to 2021 for better integration with other air quality programs such as the control of ozone and reductions in greenhouse gas emissions.

Clean Air-Clean Jobs Act

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

The Commission approved the following emission reduction plan that was in turn incorporated into the Regional Haze SIP by the AQCC in January 2011:

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

All CACJA milestones have been completed as scheduled. The only remaining actions are the installation of an SCR on Hayden 2, the retirement of Valmont 5 and the fuel switch to gas on Cherokee 4. Through this integrated plan of scheduled retirements, fuel switching and installation of emission controls, Public Service will be able to meet the requirements of Regional Haze, and utility boiler hazardous air pollutant requirements without the addition of controls beyond those noted in the CACJA plan above.

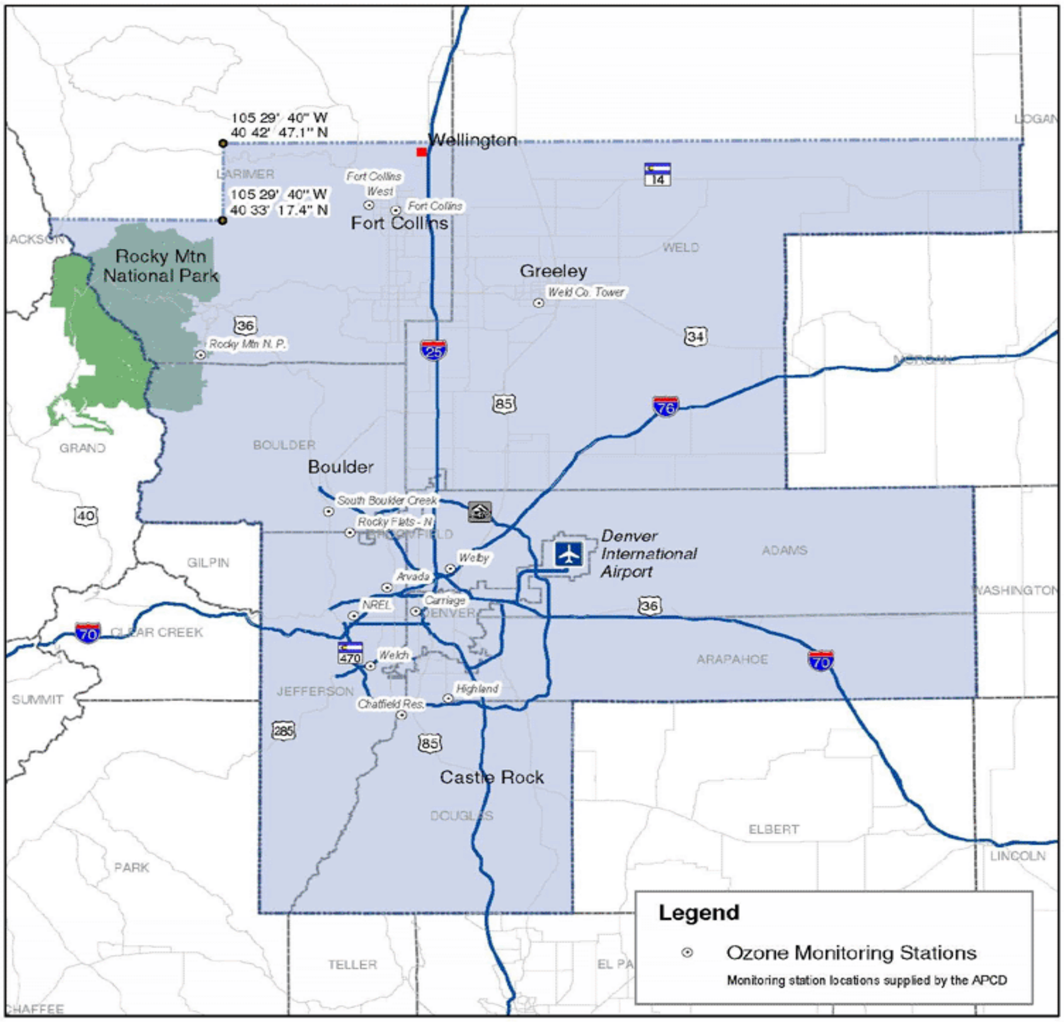
Hazardous Air Pollutants

In April 2015, EPA implemented new rules for the control of hazardous air pollutants ("HAPs") from coal-fired electric generating units. These rules required the installation of Maximum Achievable Control Technology ("MACT") to control acid gases such as hydrogen chloride, mercury and non-mercury metal HAPs such as arsenic, cadmium and lead. Emission controls such as scrubbers to control acid gases, baghouses for non-mercury metal HAPs and sorbent injection to control mercury are required to meet these new standards. Public Service is currently meeting all the requirements of these rules through the implementation of the Clean Air Clean Job Act as described above and other programs related to boiler inspections, tuning and emissions testing.

Ozone

The Denver Metropolitan Area is currently designated as attainment for all CAA criteria air pollutants such as particulate matter less than 10 microns ("PM-10"), carbon monoxide ("CO"), SO_2, and NO_x. Since 2008, however, the Denver area has not met the ambient air quality standard for ozone of 75 ppb and has therefore been designated as an ozone non-attainment area by EPA. Emissions of NO_x and volatile organic compounds ("VOCs") react in the presence of sunlight to form ozone. This non-attainment area includes the entire Denver Metro area and parts or all of surrounding counties (Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson counties as well as parts of Larimer and Weld counties). Figure 2.2-1 shows the boundaries of the current Denver Metro ozone non-attainment area. This designation has a significant impact on the permitting of new generation resources in and around Denver. While the area is designated non-attainment, any new major sources or major modifications to existing sources will have to be permitted under the non-attainment area New Source Review ("NSR") requirements. Thus, emission offsets for NO_x and VOC will be required along with the requirement to install emission controls that meet Lowest Available Emission Rate ("LAER"). LAER-based controls are very stringent and add significant expense and operating challenges to facilities. In October 2015, the EPA promulgated a new, more stringent ozone standard of 70 ppb over an 8-hour period. This more stringent ozone standard will likely expand the boundaries of the current non-attainment area north to the Wyoming boarder and south to Colorado Springs and also require additional NO_x and VOC emission reductions from stationary sources to meet the lower standard. New non-attainment area designations will be made by EPA by the end of 2017 based on ozone monitoring data for 2014 – 2017. As a result, permitting of new electric generating stations, both Company-owned and Independent Power Producer resources, will be more difficult in and around the expanded Denver Metro ozone non-attainment area.

Figure 1.2-4 Denver Ozone Non-Attainment Area



Denver-Boulder-Greeley-Fort Collins, Colorado
Eight-Hour Ozone Control Area

DRCOG
Denver Regional Council of Governments
Metro Vision Resource Center
June 2004

Regulation of Coal Ash

Public Service's power plant operations generate solid wastes that are subject to the federal Resource Conservation and Recovery Act and comparable Colorado laws that impose detailed requirements for the handling, storage, treatment and disposal of solid wastes. In April 2015, EPA finalized a rule regulating coal combustion residuals ("CCRs," sometimes referred to as “coal ash”) as non-hazardous waste and created a broad framework of technical and operational requirements for CCR management and disposal. The rule will impact the storage and disposal of fly ash in landfills and bottom ash in surface impoundments by requiring liners for new CCR Units, additional operational plans and inspections, detailed groundwater monitoring, and inactive CCR Unit closure requirements. The rule requires much operational data to be posted on a publically-accessible website and enforcement of the rule will be accomplished through citizen suits, both of which could impose significant public scrutiny on the company and its CCR operations.

Clean Water Act – “Waters of the United States”

In June 2015, EPA and the U.S. Army Corps of Engineers published a final rule that significantly expands the types of water bodies regulated under the Clean Water Act (“CWA”) and broadens the scope of waters subject to federal jurisdiction. The expansion of the term “Waters of the U.S.” will subject more Public Service projects to federal CWA jurisdiction, thereby potentially delaying the siting of new generation projects, pipelines, transmission lines and distribution lines, as well as potentially increasing project costs. For example, in Colorado, there are numerous ephemeral streams and arroyos that lack substantive flow the majority of the year, but these could now be jurisdictional and require permits and expensive mitigation measures, such as underground boring. The rule went into effect in August 2015. In October 2015, the U.S. Court of Appeals for the Sixth Circuit issued a nationwide stay of the final rule, pending further legal proceedings.

1.3 RESOURCE ACQUISITION PERIOD AND PLANNING PERIOD

Resource Acquisition Period

The Commission's resource planning rules allow jurisdictional utilities to select a Resource Acquisition Period ("RAP") of between six and ten years from the date the plan is filed. The choice of the RAP establishes the period of time for which the utility will acquire generation resources to meet projected resource needs during the ERP process. For this 2016 ERP, the Company is proposing an 8-year RAP running from the plan filing date of May 2016 through May of 2024. In practical terms, this 8-year RAP will address the Company's resource needs through the summer peak season of 2023. The choice of an 8-year RAP considered the following factors:

i. PTC and ITC extensions

In choosing the 8-year RAP, the Company considered the relationship between the RAP and the recent extension of the PTC and ITC for wind and solar resources, respectively. For PTC wind resources, the choice of the 8-year RAP is neutral since it would allow for the consideration of wind facilities that qualify for all levels of credit (100%, 80%, 60%, 40%, and 0%) as the credit is phased out over time. To qualify for the full 30% ITC, solar facilities must begin construction no later than December 31, 2019. The selection of an 8-year RAP should allow solar facilities qualifying for the full ITC to have ample time to develop and place new solar facilities in-service to meet a portion of the RAP needs.

ii. Length of time between bid submittal and resource need

At the beginning of the ERP Phase II acquisition process, power supply providers will be required to develop and submit firm priced proposals to meet the Company's anticipated resource needs during the RAP. Based upon the timing of previous ERP proceedings, it is likely that the Phase II acquisition process in this 2016 ERP will begin in the summer of 2017. As a result of the Company anticipating no resource need until the later years of the RAP, power supply providers will likely need to provide firm priced bids for projects that won't commence construction for 3 to 4 years. It becomes increasingly difficult for power supply providers (both the Company and Independent Power Producers ("IPPs")) to provide firm priced proposals as the length of time between the bidding process and the commencement of construction increases. Consequently, the Company believes that extending the RAP beyond the proposed 8 years could result in providers hedging against equipment and labor cost increases by including a premium into their proposal pricing.

iii. Length of time between completion of Phase II and the need for resources

The proposed 8-year RAP will provide sufficient time for construction of new resources from a wide variety of technologies including gas-fired combustion turbines, gas-fired combined cycle facilities, wind, and solar PV. Based on the timing of previous ERP proceedings, it is likely that the Phase II acquisition process will be completed by May 2018. This would provide approximately 24, 36, 48, or 60 months for construction of new generation facilities to meet a 2020, 2021, 2022, or 2023 resource need, respectively. This is adequate time for the construction of new resources across all major technological categories. Historically, establishing a RAP that allows sufficient time for new construction has provided an added layer of market discipline to the process. As such, providing adequate time for the construction of new resources is a benefit of the proposed 8-year RAP.

iv. Timing of the 2019 ERP

Assuming this 2016 ERP fills the Company's resource needs through 2023, the first year in which there would be a need to be filled in the next ERP is likely to be summer 2024. If the next ERP is filed by November 2019 and the associated Phase II process is completed by November 2021 (two years from the ERP filing date), there would be approximately 31 months available to construct new generation facilities and have those facilities in-service by May 2024 to meet a summer 2024 need. This is sufficient time for the construction of a wide range of technologies and, as a result, an 8-year RAP in this 2016 ERP is not expected to create a resource construction timing issue in the subsequent 2019 ERP.

Planning Period

The ERP Rules prescribe a Planning Period between twenty to forty years. Because the Strategist model that will be used in the evaluation of Phase II power supply proposals is dimensioned for years 2015 to 2054, Public Service proposes a 39-year Planning Period for the 2016 ERP.

1.4 RESOURCE NEED ASSESSMENT

For this 2016 ERP the assessment of need for additional resources focuses on four areas:

1. **Reliability** - generation capacity needed to meet planning reserve margins
2. **RES Compliance** - renewable generation needed to meet the state RES
3. **Flexible Generation** - "flexible" generation resources needed to ensure reliable integration of intermittent resources such as wind
4. **EPA Clean Power Plan (CPP)** - resources that will position the Company to comply with the carbon reduction targets envisioned in the CPP

Reliability/Capacity Need Assessment

By comparing the forecast of electric demand with the existing/planned level of generation resources and planning reserve margins over the RAP, the Company determines whether there is a need for additional generation capacity on the system. This assessment is commonly referred to as a "load and resource balance" or "L&R." Within the course of this 2016 ERP process, the Company will provide L&R projections in both Phase I and Phase II. These Phase I and Phase II L&R projections serve different purposes and are expected to vary as described below.

- ERP Phase I L&R – developed and provided at the time the Company files its 2016 ERP. Its primary function is to provide an initial projection of capacity needs (a.k.a., resource needs) that: 1) are used in the modeling of Alternative Plans under Rule 3604(k), and 2) could be filled in the Phase II acquisition process. The Phase I L&R utilizes the Company's December 2015 forecast of firm electric demand[2] to represent the "load side" of the balance and, existing generation resources as well as planned generation resources to be acquired in other proceedings[3] to represent the "resource side" of the balance. The Phase I L&R is not intended to be the definitive representation of the resource needs the Company will fill in the Phase II competitive resource acquisition process.

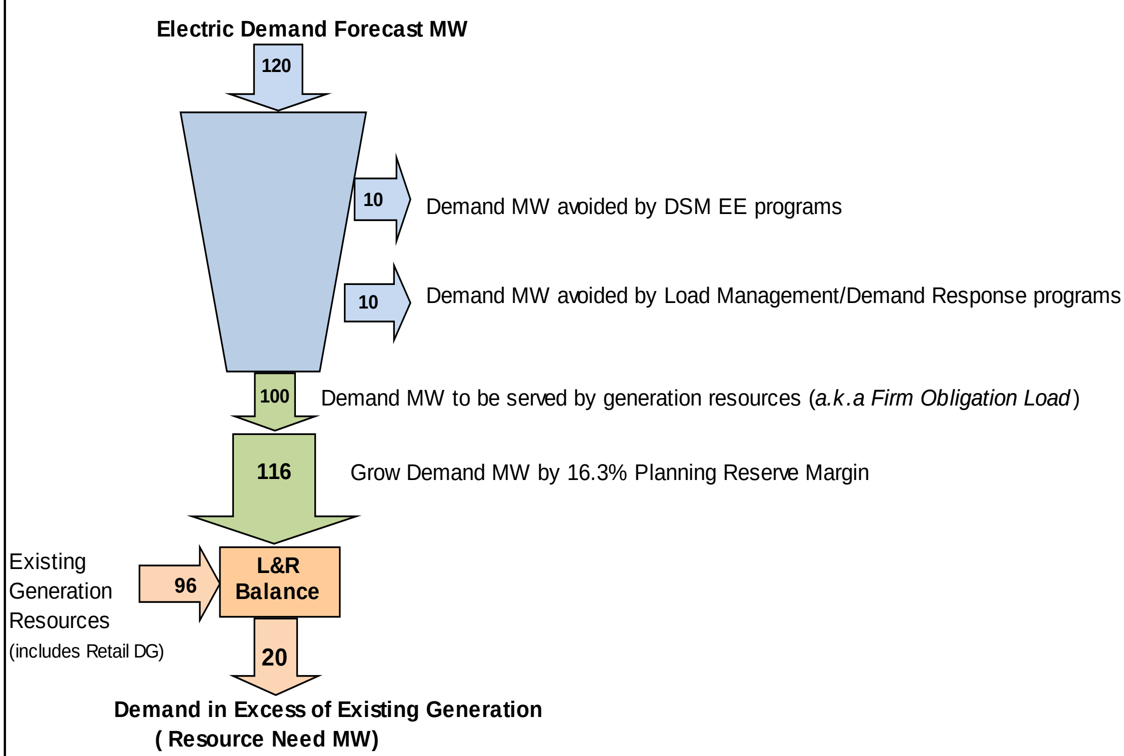
- ERP Phase II L&R – developed prior to receipt of bids in the 2016 ERP Phase II acquisition process to represent the resource needs to be filled through that process. This Phase II L&R is certain to show a different level of

[2] For consistency purposes, the retail sales portion of the forecast is the same forecast filed in the Company's 2017 Renewable Energy Plan and in the Company's Rule 3660(h) filing.

[3] Rush Creek Wind Project (Proceeding No. 16A-0117E); Solar*Connect (Proceeding No.16A-0055E), 2017 Renewable Energy Plan (Proceeding No. 16A-0139E).

resource need than that shown in Phase I. This is due to the fact that the Phase II L&R will not only reflect an update to the Company's demand forecast, but also the Commission decisions from Phase I of the 2016 ERP and other proceedings that impact the determination of resources need. These could include Phase I ERP decisions related to the Company's demand forecast methodology, effective load carrying capacity ("ELCC") levels for intermittent generation resources, as well as decisions from other proceedings such as the 2017 RE Plan, Solar*Connect, and the Rush Creek Wind Project that impact the level of planned generation during the RAP. By updating the L&R balance at the time of the Phase II competitive acquisition process, the Company will better ensure that we acquire the appropriate amount of generation resources to reliably serve the peak demands during the RAP.

Figure 1.4-1 Basic Reliability/Capacity Need Assessment



Note: The values in this figure are illustrative.

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 and Solar*Community solar gardens programs.

ERP Phase I L&R

Table 1.4-1 summarizes the Company's assessment of the need for additional generation capacity. The detailed L&R used to produce Table 1.4-1 is included in Section 2.12 of ERP Volume 2.

Table 1.4-1 ERP Phase I L&R Projection of Resource Need (MW)

	RAP Year =>	1	2	3	4	5	6	7	8
Row		**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
A	Existing & Planned Generation	7591	7587	7501	7446	7554	7585	7360	7103
B	Firm Obligation Load	6083	6157	6193	6286	6347	6479	6538	6602
C	16.3% Reserve Margin	1032	1044	1049	1065	1075	1096	1106	1116
A-(B+C)	**Capacity/Resource Need (1)(2)**	**476**	**387**	**259**	**95**	**133**	**11**	**(284)**	**(615)**
Notes:	(1) Positive values = capacity surplus, (negative values) = capacity shortfall or resource need								
	(2) Needs are cumulative								
	(3) Rush Creek firm capacity accredited to 600 MW based on a 8.2% ELCC. 0.082 x 600 MW = 49 MW								

Embedded within the existing & planned generation values in Table 1.4-1 are the planned generation additions reflected in the Company's 2017 RE Plan (Proceeding No. 16A-0139E), the Company's proposed Solar*Connect Program (Proceeding No. 16A-0055E), and the Company's proposed Rush Creek Wind Project (Proceeding No.16A-0117E). Consistent with prior practice, the Company has also projected continued annual acquisitions of Retail DG at the same levels as proposed in the 2017 RE Plan throughout the RAP. Public Service will update these estimates in accordance with the Commission decisions in these proceedings when determining the resource needs to be filled through the Phase II acquisition process. Also embedded within the existing & planned generation values in Table 1.4-1 are the retirements of six coal fired units (Arapahoe units 3 and 4, Cherokee units 1, 2 and 3, and Valmont 5), the fuel switching of Cherokee 4 to burn natural gas, and the addition of the Cherokee gas-fired combined cycle facility. These resource retirements and additions are part of the Commission approved plan for implementing the Clean Air-Clean Jobs Act ("CACJA"). In total, the retirements/fuel switch represent the retirement of over 1,000 MW of coal-fired generation.[4]

Embedded within the firm obligation load values in Table 1.4-1 are the demand reduction effects of the Company's energy efficiency, Savers Switch, Interruptible

[4] Arapahoe 3 (45 MW), Arapahoe 4 (111 MW), Cherokee 1 (107 MW), Cherokee 2 (106 MW), Cherokee 3 (152 MW), Cherokee 4 (352 MW), Valmont 5 (184 MW).

Service Option Credit and Third Party Demand Response programs. Furthermore, the firm obligation load includes a forecast of the City of Boulder's entire firm load obligation over the 8-year RAP. Notwithstanding Boulder's stated intentions to form a municipal utility system, the Company has a continuing legal obligation to plan its system to serve Boulder's load.

Uncertainty in Phase II Resource/Capacity Need Assessment

Inherent in any forecast of resource need is the uncertainty associated with the Company's forecast of customer demand for electric service that is tied to the local economic conditions. In this 2016 ERP, the Company faces additional uncertainties that could influence both the generation and load sides of the L&R balance in Table 1.4-1, and as a result act to either increase or decrease the resource needs which will ultimately be filled in the Phase II process.

- *Generation Uncertainties:*
  - Solar*Connect
  - Rush Creek Wind Project
  - Customer Choice Solar Programs

In these proceedings, the Company has proposed to acquire additional renewable resources. In the event that some of these proposed resources are not approved, or if actual participation in Customer Choice Solar programs is lower than anticipated, the amount of generation resources ultimately acquired could be lower than anticipated resulting in an increase in the Company's resource need from that depicted in Table 1.4-1. For example, if neither Solar*Connect nor the Rush Creek Wind Project were to be approved and participation in Solar Choice programs was 50% of the anticipated level over the RAP period, then the 2023 resource need would be ~175MW higher than the current forecast.

- *Load Uncertainties:*
  - Oil and gas load (could either increase or decrease need)
  - Grid modernization (AGIS) + TOU rates acts to reduce need

There are also a number of factors (beyond normal load forecast uncertainty) that may affect the level of obligation load that the Company will serve at the end of the RAP. In particular, the base forecast assumes incremental oil and gas related load that will be added to the system (~200 MW by 2023.) If this load were to materialize at higher or lower levels than anticipated, it would change the Company's obligation load in the RAP. For example, if incremental oil and gas loads materialized at levels 50% higher than anticipated, it would increase the Company's 2023 resource need by ~125 MW. Similarly, incremental oil and gas loads at levels 50% lower than anticipated would decrease the Company's 2023 resource need by ~125 MW.

In addition, it is possible that by the end of the RAP the Company's proposed future filing for components of the Advanced Grid Intelligence and Security ("AGIS") initiative and Time of Use residential rates ("RTOU") may lower the peak demand on the system. While the final characteristics of these programs are still the subject of ongoing analysis and regulatory treatment, it is plausible that they could reduce net obligation load by between ~100 MW and ~300 MW by the end of the RAP.

Finally, as always, any load forecast updates will reflect updated trends in underlying econometric factors that will serve to raise or lower the anticipated obligation load. While the level of anticipated load will fluctuate with each forecast update, the most recent update (April 2016) did show a lower overall demand trend (~100 MW) per year relative to the December 2015 load forecast used to develop the 2016 ERP. While this level of obligation load will likely change (either increasing or decreasing) in the next update, this level of change does serve to illustrate the level of uncertainty inherent in any load forecast.

Table 1.4-2 provides a summary of how the various generation and load side uncertainties could impact the resource/capacity need that is ultimately filled through the Phase II process.

Table 1.4-2 Approximate Impact on Resource Need (MW)

	Uncertainty	2018	2019	2020	2021	2022	2023
Generation Impact	Solar*Connect (if not Approved)		+15	+15	+15	+15	+15
	Rush Creek (if not Approved)		+49	+49	+49	+49	+49
	Additional Customer Choice Solar (1)	+50	+85	+120	+150	+185	+215
Load Impact	Oil and Gas (High) (4)	+15	+50	+70	+125	+125	+125
	Oil and Gas (Low) (4)	-15	-50	-70	-125	-125	-125
	Residential Demand Rates (Low) (3)				-100	-100	-100
	Residential Demand Rates (High) (3)				-300	-300	-300
	April 2016 Forecast (2)	-100	-95	-115	-85	-85	-90

Notes:
1) Total nameplate of customer choice assumed to be added from 2017-2023 is approxmately 600 MW
2) Differences due only to Econometric factors
3) Residential Demand Rates could be enabled by AMI infrastructure and the forthcoming Grid CPCN filing
4) High/Low Oil and Gas Load sensitivities assume +/- 50% of expected impact respectively

In addition to all of the uncertainty factors affecting load and generation levels discussed above, it is also important to note that the Company's need assessment includes achievement of all goals related to Demand Side Management/Energy Efficiency and Demand Response as ordered in the 2013 Strategic Issues Decision (C14-0731.) Specifically, the Company's load forecast assumes the ordered levels of 65 MW per year of DSM peak reduction and a level of Demand Response consistent with those in the order. If these goals were to change in subsequent proceedings, this could impact the Company's projected resource needs.

<u>RES Compliance Need Assessment</u>

The state of Colorado's Renewable Energy Standard ("RES") consists of three categories of renewable energy resources: 1) Non-Distributed Generation ("DG"), 2) Wholesale DG, and 3) Retail DG. The Company acquires Non-DG and Wholesale DG resources through its ERP process while Retail DG resources are acquired through the Company's Solar*Rewards and Solar*Rewards Community solar gardens programs that are filed in accordance with the Commission's RES rules (Rules 3650-3669). This assessment of RES compliance need is therefore limited to the need for additional Non-DG and Wholesale DG resources.

The Company's prior achievements in acquiring cost-effective renewable resources for customers through the ERP process has placed it ahead of schedule in complying with the RES. Public Service projects that it does not need to acquire any additional Wholesale DG or Non-DG eligible energy resources to comply with the minimum requirements of the RES through 2030. As a result, there is no need to set aside any portion of the resource needs to be acquired in the Phase II process for additional renewable resources for the sole purpose of meeting the RES. This does not, however, preclude the Company from encouraging power supply providers to offer renewable resources to Public Service in Phase II based on: 1) the projected cost savings they can bring to customers (due in large part as a result of recent federal tax credit extensions) and 2) the value that renewable resource bring towards better positioning the Company to comply with future state and federal carbon reduction goals and requirements.

<u>Flexible Generation Need Assessment</u>

In order to reliably integrate wind generation onto its system, the Company has created a supplemental reserve category designed to address large reductions of online wind generation due to losses in wind speed. This reserve category is listed as Schedule 16: Flex Reserve Service on the Company's transmission tariff. This new 30-minute Flex Reserve Service replaces the Company's prior 30-Minute Wind Reserve Guideline.

The Company calculated 30-Minute Flex Reserves by analyzing historic, 30-minute wind generation down ramps on its system. From an analysis of these wind down ramps it determined the MW level of 30-minute responsive generation (i.e. the 30-Minute Flex Reserve) required for reliable operations as a function of wind generation levels. The details of how the Company calculates 30-Minute Flex Reserves are provided in a 30-Minute Flex Reserve study report included in Section 2.13 of Volume 2.[5]

The study examined required Flex Reserve levels for the Company's current wind portfolio and for incremental portfolios with up to 3,174 MW of wind generation which is an incremental 800 MW of wind above the current portfolio less 192 MW of existing wind with PPA terms that expire shortly. The study indicated that the current portfolio of Flex Reserve capacity is sufficient to reliably integrate the highest level of incremental wind examined. The Company is currently working to expand the study to evaluate the impacts on Flex Reserve requirements for an additional 600 MW of wind above the maximum level already studied (3,774 MW total).

Should the expanded study report indicate that incremental Flex Reserves should be acquired to reliably integrate 3,774 MW of wind generation, the Company has identified several low cost sources from which it could obtain additional Flex Reserve capacity. Specifically the Company could install additional load commutated inverters ("LCIs") at its Blue Spruce and Fort St. Vrain generating stations so that both Blue Spruce combustion turbines (Units 1 and 2) or both Fort St. Vrain combustion turbines (Units 5 and 6) could be started simultaneously.[6] In addition, the Company currently purchases capacity and energy from the IPP-owned Spindle Hill facility; an additional LCI at Spindle Hill would also allow the two combustion turbines at that facility to start simultaneously and provide incremental Flex Reserve capacity.

EPA Clean Power Plan Need Assessment

Background

On August 3, 2015, the U.S. Environmental Protection Agency issued its final Clean Power Plan, one of the most ambitious regulations in decades, designed to reduce carbon dioxide (CO_2) emissions from the nation's power plants. The final rule establishes a baseline year of 2012, which means only those utility actions made post-2012 will count towards meeting the CO_2 emission reduction targets. For Colorado, the goal is to reduce the rate of CO_2 emissions from existing power plants

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[5] The Flex Reserve Study was submitted in Proceeding No. 16A-0117E in support of the Company's 600 MW Rush Creek Wind Project and is included in Volume 2 for ease of reference.

[6] In Proceeding No. 16A-0117E for the 600 MW Rush Creek Wind Project, the Company indicated that it would be installing an additional LCI at the Fort St. Vrain site.

by 40 percent, or to reduce the mass (total number of tons) by 28 percent from 2005 levels by 2030.

The CPP establishes that states are expected to work with their local utilities and other stakeholders to develop compliance plans. For the state of Colorado, the Colorado Department of Public Health and Environment ("CDPHE") has been tasked with developing the state's compliance plan. Public Service has and continues to participate in CDPHE's efforts in this regard. However, as a result of the Supreme Court stay of the Clean Power on February 9, 2016, pending judicial review, additional uncertainty exists as to the ultimate outcome of the rule as well as CDPHE's schedule for developing and filing the state compliance plan with EPA.

Current Company Actions

Public Service has been working to reduce emissions of CO_2 as a result of the Company's electric power supply operations for years. Our most recent actions that we fully expect to help the Company meet state compliance goals include:

1. the retirement of approximately 900 MW of coal fired generation resources by 2018 through the Clean Air-Clean Jobs Act;
2. the addition of 450 MW of wind generation and 170 MW of utility scale solar generation through Phase II of the 2011 ERP;
3. the recent CPCN application to construct the 600 MW Rush Creek Wind Project under Commission Rule 3660(h); and
4. the Company's 2016 DSM plans to achieve approximately 400 GWh of energy efficiency savings annually through 2020.

General Company Assessment

Absent the details that a state compliance plan would provide[7], the Company is limited in its ability to provide a detailed assessment of not only the additional CO_2 reductions it may be required to achieve, but also both the type of actions (e.g., renewable additions, gas-shifting[8], early coal retirements) and timing of actions that would meet the required reductions in a least-cost manner. Details of a state compliance plan that would be needed in order for Public Service to provide a detailed assessment include, but are not limited to:

1. Determination of whether the state plan will be rate based or mass based
2. Emissions allowance allocation methodology (mass based)

[7] Even a state compliance plan that has yet to be approved by EPA would provide considerable guidance as to the additional CO_2 reductions Public Service would need to achieve.

[8] Gas-shifting generally refers to shifting generation from affected coal units to affected gas-fired combined cycle units.

3. Design and administration of potential set aside pools (mass based)
4. Final timelines for interim compliance and final compliance
5. ERC evaluation and measurement requirements (rate based)
6. ERC and allowance banking provisions (rate and mass based)
7. State based rate or segmented (unit by unit) rate compliance (rate based)

Despite lacking a state compliance plan for Colorado, the Company believes that its analysis of alternative plans discussed in Section 1.5 of Volume 1 does identify certain actions that the Company should pursue in this 2016 ERP that represent a strategy that will ultimately put Public Service and its customers in a better position for complying with the CO_2 emission reductions envisioned in either the CPP or other future state and federal carbon reduction goals/requirements. This strategy involves:

1. Action to ensure the Company can take advantage of the recently extended federal PTCs for new wind generation resources. The Company has initiated this action by filing an application with the Commission to develop the 600 MW Rush Creek Wind Project under Commission Rule 3660(h). This additional 600 MW of PTC wind is expected to eliminate over 5 million tons of CO_2 emissions from affected coal and gas-fired CC units during the RAP.
2. Actions in this 2016 ERP to encourage additional cost effective utility-scale wind and solar resources be offered to the Company in the Phase II acquisition process. These actions include expanding the competitive acquisition process to include RFP documents and processes to allow the acquisition of utility-scale wind and solar through power purchase agreements with IPP's as well as Company ownership through build-own-transfer ("BOT") arrangements with IPPs.
3. Continued commitment to investing in Colorado consumers and providing them choices for their energy needs through the Company's 2017 RE Plan which lays out a three-year roadmap to providing our customers affordable and clean energy options that support their environmental preferences and sustainability goals. The 2017 RE Plan proposes to: 1) add capacity to our Small Solar*Rewards and Medium Solar*Rewards rooftop programs; 2) reopen our Large Solar*Rewards rooftop program; and 3) add more minimum levels of capacity every year for our Solar*Rewards Community solar gardens program. In a separate application, the Company has also proposed a new solar program called Solar*Connect which, if approved by the Commission, will give customers additional solar choices.

Public Service believes that these actions to acquire additional renewable generation for our customers that take advantage of the recent PTC and ITC extensions, coupled with our continued efforts in the area of DSM and customer choice programs, will further enhance the Company's position to address future public policy regulations regarding carbon.

1.5 ALTERNATIVE PLANS

Section Overview

Commission 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 Section 124 renewable energy resources, demand-side resources, or Section 123 Resources that could potentially be part of a cost-effective resource plan. This section of the 2016 ERP describes how Public Service developed alternative plans to meet this rule requirement.

Public Service segmented the analysis of alternative plans into two different time frames: 1) the 8-year RAP (2016-2024) and 2) beyond the RAP (2024-2054) [9]. The analysis of renewable additions made during the 8-year RAP is intended to provide cost and benefit information that aligns with the timeframe of decisions before this Commission in this 2016 ERP. The analysis of renewable additions made beyond the RAP (i.e., starting in 2024 and going out to 2054) is intended to show how the decisions made in this ERP regarding the addition of renewable energy resources can set the foundation for future ERP proceedings. Figure 1.5-1 illustrates this segmented approach.

[9] All alternative plans were analyzed over a 39-year planning period.

Figure 1.5-1 Alternative Plan Analysis Framework[10]

Alt Plan	RAP Renewable Additions Analysis		PVRR
	2016-2023 RAP	**2024-2054**	
1	Baseline Case - no new renewables	Evaluate planning period costs/benefits of ***RAP renewable additions***	$100
2	Add 600 MW Wind	Evaluate planning period costs/benefits of ***RAP renewable additions***	$90
3	Add 1,000 MW Wind	Evaluate planning period costs/benefits of ***RAP renewable additions***	$85
4	Add 600 MW Wind + 400 MW Solar	Evaluate planning period costs/benefits of ***RAP renewable additions***	$80

Alternative plan 4 from the "RAP Renewable Additions Analysis" above was further evaluated by adding additional renewable resources in years beyond the RAP. This additional analysis is denoted as the "Post-RAP Renewable Additions Analysis" below.

Alt Plan	Post-RAP Renewable Additions Analysis		PVRR
	2016-2023 RAP	**2024-2054**	
4A	Add 600 MW Wind + 400 MW Solar	Evaluate planning period costs/benefits of ***level A of Post-RAP renewable adds***	$85
4B	Add 600 MW Wind + 400 MW Solar	Evaluate planning period costs/benefits of ***level B of Post-RAP renewable adds***	$95
4C	Add 600 MW Wind + 400 MW Solar	Evaluate planning period costs/benefits of ***level C of Post-RAP renewable adds***	$100
4D	Add 600 MW Wind + 400 MW Solar	Evaluate planning period costs/benefits of ***level D of Post-RAP renewable adds***	$105

PVRR Values at the far right of the figure are for illustration purposes only.

The top half of Figure 1.5-1 depicts how the Company first developed alternative plans that included additional renewable resources only during the 8-year RAP

[10] All PVRR values are for illustration purposes only and are not intended to be indicative of the costs and benefits of renewable resources.

(Alternative Plans 1, 2, 3, and 4). No additional renewable resources were added to the system beyond 2023 in these plans. The purpose of these plans was to evaluate the costs and benefits of renewable resources that might be added through this 2016 ERP.

The bottom half of Figure 1.5-1 depicts the alternative plans that were developed for the purpose of evaluating the costs and benefits of adding more renewable resources to Alternative Plan 4 in years 2024-2054 (referred to as Post-RAP renewable additions). In other words, Public Service took Plan 4 as a starting point and then evaluated the cost/benefits of different levels of renewable additions that might occur in years beyond the RAP. These different levels of post-RAP renewable additions are denoted as alternative plans 4A, 4B, 4C, and 4D. Given that alternative plan 4 contains a mix of both additional wind and solar during the RAP, it was selected to serve as the starting point for examining renewable additions beyond the RAP.

Resource Technologies Used in Alternative Plan Analysis

A combination of generation resource technologies were used in developing the alternative plans. For wind generation qualifying for 100% of the PTC, cost and performance information was based on the 600 MW Rush Creek Wind Project for which the Company has filed a CPCN with the Commission. Generic cost and performance estimates were used to represent wind generation qualifying for 80% of the PTC. Solar and gas-fired generation technologies are also represented using generic cost and performance estimates. These estimates are referred to as “generic” because they do not reflect a specific site location. The estimates do however include all major cost and performance characteristics[11] for a facility located within Colorado. The Company considers all the generic resources used in the alternative plans to be commercially demonstrated technologies and available in the market to fill its projected resource needs in this ERP.

Regarding Section 123 resources, in its 2011 ERP Phase I Decision, the Commission approved a three-step process through which the Company was to evaluate Phase II bids that claimed Section 123 status.[12] In that same Decision, the Commission decided not to opine until after Phase II bids were received as to the Section 123 classification of technologies presented by two intervening parties.[13] Given the three-step process approved by the Commission and the Commission’s preference to review Section 123 claims in a Phase II proceeding, Public Service

[11] For example, the impact of elevation on gas-fired unit ratings, solar irradiance for Colorado and wind production for Colorado locations.
[12] Decision No. C13-0094, Paragraphs 161-163.
[13] Decision No. C13-0094, Paragraph 104.

has chosen not to model any potential Section 123 technologies in its Phase I alternative plan analyses.

Regarding DSM energy efficiency and demand response, in its 2011 ERP Phase I Decision addressing applications for rehearing, reargument, or reconsideration, the Commission agreed with the Company that it was more practical to address the acquisition of energy efficiency and demand responses in a process separate from the ERP.[14] In its Decision approving the Company's Demand Side Management Plan Strategic Issues filing, the Commission set the Company's goals for energy efficiency and demand reduction through 2020.[15] Given the Commission's prior decisions on how best to determine the cost-effective levels of incremental energy efficiency and demand reduction outside of an ERP, the Company has chosen not to model additional demand-side resources (i.e., in addition to those currently on the system) in its Phase I alternative plan analyses.

Tables 1.5-1 and 1.5-2 summarize the generation technologies used in constructing the alternative plans. Table 1.5-1 only includes those dispatchable technologies that were selected by the Strategist model for inclusion in the various alternative plans. Additional dispatchable technologies were made available to the model but were not selected. A complete accounting of all dispatchable technologies that were made available to Strategist for inclusion in the alternative plans is contained in Section 2.7-10 of ERP Volume 2.

[14] Decision No. C13-0323. Paragraph 41.
[15] Decision No. C14-0731. Paragraphs 19 and 60.

Table 1.5-1 Generic Dispatchable Resource Cost and Performance

Dispatchable Resources [1,2]	2x1 CC [5,6]	Large CT [7]
Summer Peak Capacity (MW)	658	192
Fuel Source [3]	Nat Gas	Nat Gas
Capital Cost ($/kW) [4]	$843	$610
Book Life	40	40
Fixed O&M Cost ($000/yr) [4]	$5,650	$464
Variable O&M Cost ($/MWh)	$0.39	$1.28
Ongoing Capital Expenditures ($000/yr)	$3,509	$1,692
Heat Rate 100 % Loading (btu/kWh)	6,925	9,955

Notes:

(1) All Costs in year 2015 dollars

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

(3) For all units, a firm fuel charge of $6.16/kW-yr (levelized) has been applied

(4)$/kW costs are based on Winter Capacity. Estimates of generic capital and fixed O&M costs are based on the midpoint between the costs of a greenfield EPC facility and those of a brownfield facility. Brownfield costs are estimated by removing certain cost items from the greenfield estimate but costs for an actual brownfield facility are very site specific. To estimate the midpoint costs for combined cycle units, greenfield capital and fixed O&M costs have beem reduced by 7.5% and 20% respectively from greenfield costs. To estimate the midpoint costs for combustion turbine units, greenfield capital and fixed O&M costs have been reduced by 12.5% and 20% respectively.

(5) For all combined cycle units, a levelized $25/kW-yr charge has been applied to estimate transmission interconnection costs

(6) Based on Siemens 5000F 2x1 CC

(7) Based on Siemens 5000F SC

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.

Table 1.5-2 Renewable Resource Cost and Performance

	RAP Renewables			Post - RAP Renewables	
Renewable Resources	**100% PTC Wind (1)**	**80% PTC Wind**	**30% ITC Solar**	**0% PTC Wind**	**10% ITC Solar**
Nameplate Capacity (MW)	600	400	50	200	50
ELCC Capacity Credit (%)	8.2%	9.0%	25.0%	9.0%	25.0%
Levelized Variable Cost ($/MWh) (2)	$28.68	$37.35	$53.82	$61.05	$61.62
Capital Cost ($/kW) in 2015 Dollars	$1,525 (3)	$1,450	$1,393	$1,450	$1,313
Transmission Cost ($/kW) in 2015 Dollars	$187	$92	$87	$92	$82
Capacity Factor	43.6%	41.5%	29.6%	41.5%	29.6%
Book Life (Years)	25	25	30	25	30
Assumed COD	2019	2020	2022	2023	2025

Notes:
(1) 100% PTC Wind cost and performance represented using the Rush Creek Wind Project
(2) Includes captial cost to construct & transmission to interconnect and deliver. Costs levelized over the book life.
(3) In 2019 Dollars

Major Assumptions Used in Modeling of Alternative Plans

Alternative plans were developed using the Strategist computer model with the same input assumptions as those included in Attachment A, filed with the Commission February 29, 2016 in Proceeding No. 16A-0138E with the exception that the modeling of plans used updated values for: 1) wind and solar integration costs, and 2) coal cycling costs.

At the time Public Service provided Attachment A assumptions filing in Proceeding No. 16A-0138E on February 29, 2016, study work was still ongoing for flex reserve adequacy. Such study work to examine 600 MW of additional wind is complete and is provided for reference in Section 2.13 of Volume 2. The Company is currently expanding that flex reserve adequacy analysis to examine our ability to accommodate more than 600 MW of additional wind generation. The expanded flex reserve analysis will be completed and provided to parties in this ERP proceeding as soon as practicable.

At the time Public Service provided the February 29, 2016 Attachment A assumptions filing in Proceeding No. 16A-0139E, study work had been completed for wind and solar ELCC values but the study reports were not complete. The ELCC values produced by that completed study work and identified in the February 29, 2016 Attachment A assumptions filing were used in the development of alternative plans. The solar ELCC study report is provided as Attachment KLS-2 to the direct testimony of Company witness Mr. Kent Scholl. The wind ELCC study was filed in

Proceeding No. 16A-0017E and is included for reference in Section 2.13 of ERP Volume 2.

The firm fuel cost assumption of a levelized $6.16/kW-mo provided in the February 29, 2016 Attachment A assumptions filing was utilized in the modeling of alternative plans.

Discussion on Integration Costs for Intermittent Generation

Given that the alternative plans examine the costs and benefits of increasing levels of renewable resources, a separate discussion of the integration costs included in those plans is warranted. The Company examines and estimates certain costs required to reliably integrate intermittent generation onto its power supply system. These integration costs are often referred to as the "hidden" costs of wind and solar. When considering the different generation technologies available to the Company to meet its resource needs, it is important to include the appropriate integration costs in any modeling to ensure an accurate cost comparison between intermittent and non-intermittent alternatives. In the modeling of alternative plans, four separate categories of integration costs are represented.

1. Wind Integration Costs

   The Company's most recent wind integration cost study was documented in the August 29, 2011 study report titled "Public Service Company of Colorado 2 GW and 3 GW Wind Integration Cost Study". The study is included for reference in Section 2.13 of ERP Volume 2. The study was designed to estimate the costs of total interconnected wind levels of approximately 2,000 MW and 3,000 MW that arise from the uncertain and variable nature of wind generation. Specifically, the study examined costs related to three major areas: system operations, regulation, and gas storage. System operations costs were studied as a function of natural gas prices with annual average gas prices examined at five different levels with a minimum of $3.24/MMBtu and a maximum of $12.00/MMBtu. System operations costs were found to account for ~90% of the total integration costs across the three categories studied.

   The current annual average base gas price forecast used in the alternative plan analysis ranges from $2.13/MMBtu in 2016 increasing to $9.58/MMBtu in 2054. The average annual base gas price forecast in 2019 (the first year in which incremental wind generation was studied under the Alternative Plans) is $2.83/MMBtu, below the minimum $3.24/MMBtu gas price studied. Commission Staff identified that the current gas price forecast was below the level examined in the 2 GW 3 GW wind integration study. To address Staff's concern on this issue, in the analysis of alternative plans, Public Service did not allow the wind integration costs modeled in Strategist to fall below $2.93/MWh, which is the integration cost associated with a gas price of $3.24/MMBtu.

2. <u>Solar Integration Costs</u>

Average solar integration costs included in the alternate plans are shown in Table 2.7-8 in Volume 2. These values were based on the results of the solar integration cost study provided as Attachment KLS-1 to the direct testimony of Company witness Mr. Kent Scholl. For the alternate plan modeling, the Company applied the results from the higher levels of solar examined in the study.

3. <u>Coal Cycling</u>

Average coal cycling costs included in the alternate plans are shown in Table 2.7-7 in Volume 2. These values were calculated in the model described in the coal cycling cost study provided for reference in Section 2.13 of ERP Volume 2.[16]

4. <u>Flexible Generation</u>

The cost of adding a LCI to Fort St. Vrain Units 5 and 6 was included in the modeling of alternative plans 2,3,4, 4A, 4B, 4C, and 4D at an estimated cost of $3 million. In Proceeding No. 16A-0117E, the Company stated that it would add this LCI.

Alternative Plans

The basic computer modeling framework used to develop and analyze alternative plans consists of a series of steps that are summarized below.

Alternative Plan Development Process

<u>Step 1 - Construct Strategist Model</u>

The Public Service electric supply system was represented within Strategist to reflect the Company's existing generation mix (both owned and purchased) as well as planned, but yet to be completed, generation resource additions and retirements resulting from the 2011 ERP and CACJA[17] respectively. A long term forecast of electric sales and demand for the Public Service system are included as an input into the Strategist model. Embedded within the long-term sales and demand forecast are demand reductions and energy savings consistent with a

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[16] The coal cycling study was submitted for review in Proceeding No. 16A-0117E.

[17] Including all additional actions related to CACJA, the 2013 All-Source Solicitation, and Strategic Issues DSM Targets.

level of DSM resources that the Commission established in Proceeding No. 13A-686EG. The Company's interruptible programs are also represented in the model as supply-side resources that the model can dispatch when appropriate.

The resulting model representation showed a need for additional generation capacity within the 8-year RAP totaling approximately 615 MW 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. The need for additional capacity both within the RAP and beyond arises from a combination of electric load growth and assumed Company owned resource retirements and PPA expirations.

Step 2 - Develop Alternative Plan 1 (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 the 615 MW of RAP capacity needs as well as the need beyond the RAP from the pool of gas-fired generic dispatchable resources summarized in Table 1. Additional utility scale renewable resources were not included in alternative plan 1.[18] The resulting baseline case formed the modeling foundation upon which the various alternative plans with increasing amounts of renewable resources were built. The primary purpose of alternative plan 1 is to serve as a cost foundation (measured in PVRR) against which the costs and benefits of the other alternative plans are measured. Alternative plan 1 does not represent an alternative plan that Public Service would consider pursuing.

Step – 3 Develop Alternative Plans

Alternative plan 1 formed the foundation upon which alternative plans that include increasing amounts of renewable resources were built. Alternative plans were built by first manually adding renewable resources as defined in Table 1.5-2 into alternative plan 1 (a.k.a., "hard wiring"[19]) and then allowing the model to optimize the type, amount, and timing of gas-fired generic resources from Table 1.5-1 that in combination with the renewable additions would serve the system needs over the planning period in a least-cost manner.

[18] Alternative plan 1 does include an assumption that participation in customer choice programs such as Solar Rewards and Solar Communities will grow each year at approximately 105 MW_{DC}.

[19] The term "hard wiring" in this instance refers to a generic resource being manually input into the Strategist model to begin its operating life in a specific year.

Alternative Plan 1 – No New Renewables

Alternative plan 1 developed in Strategist includes two large gas-fired combustion turbines (CT) and one 2x1 gas-fired combined cycle (CC) to meet the resource needs during the RAP. With lower capital costs but higher operating costs than CC technologies, CTs serve a "peaking" role in that they operate few hours during the year, mostly during peak load conditions, and function to provide mostly generation "capacity" to the system. The absence of additional renewable energy resources in alternative plan 1 results in the 2x1 CC being selected to serve a portion of the RAP capacity and energy needs. This is due to the fact that renewable resources provide value to the system through the energy they provide toward serving system load. As a result, renewables are thought of as "energy resources". As a result of there being no additional renewable resources added in alternative plan 1, the model makes the economic choice to add the CC in the RAP instead of more CTs. Although the CC has higher capital costs than the CT, its lower heat rate and hence lower energy cost makes it the most economical choice for providing energy to the system in lieu of that which renewable additions would have provided.

Furthermore, selection of large CT technology over LMS[20] and aero-derivative technology in the alternative plan modeling is in most part due to the significantly higher capital cost of the LMS and aero technologies, which can be 200% to 300% higher than that of large CTs.

Again, the primary purpose of alternative plan 1 is to serve as a cost foundation (measured in PVRR) against which the costs and benefits of the other alternative plans are measured. Alternative plan 1 does not represent an alternative plan that Public Service would consider pursuing.

Organization of Alternative Plan Analysis Discussion

The remainder of this section is organized to first discuss the analysis of increasing levels of renewable generation added to the system during the 8-year RAP followed by a discussion of increasing levels of renewable generation added to the system in years beyond the RAP. As identified in Figure 1.5-1 earlier, these two analyses focus on renewable generation being added to the system in different timeframes and will be collectively referred to herein as the *"RAP Additions Analysis"* and the *"Post-RAP Additions Analysis"* respectively**.**

[20] LMS is an acronym used by General Electric in naming one of their models of CTs.

RAP Additions Analysis - Alternative Plans

Public Service developed a total of four alternative plans to evaluate the costs and benefits of increasing amounts of solar and wind renewable resources added to the system during the 8-year RAP. A summary of the resource additions in each of these alternative plans is included in Figure 1.5-2. All PVRR values reported in this alternative plan section are rounded to the nearest $10 million.

Figure 1.5-2 RAP Additions Analysis - Alternative Plans 1, 2, 3, and 4

RAP Renewable Resource Additions	Alternative Plan			
	1	2	3	4
Baseline Case/Alterative Plan 1 (1)	-	-	-	-
600 MW 100% PTC Wind (2)	-	600 MW	600 MW	600 MW
400 MW 80% PTC Wind (3)	-	-	400 MW	-
400 MW 30% ITC Solar (4)	-	-	-	400 MW
Total RAP additional Renewables	**0 MW**	**600 MW**	**1,000 MW**	**1,000 MW**
RAP Non-Renewable Additions				
Large Combustion Turbine (CT)	2 CTs 410 MW	4 CTs 820 MW	4 CTs 820 MW	3 CTs 615 MW
2x1 Combined Cycle (2x1 CC)	1 CCs 700 MW	-	-	-
Total RAP additional Non-Renewables	**1110 MW**	**820 MW**	**820 MW**	**615 MW**
PVRR Delta From Baseline ($M) (5)	**$0**	**($440)**	**($590)**	**($570)**

Notes:
(1) Includes 450 MW of wind and 170 MW of solar selected in the 2011 ERP, 2017 RE Plan additions, and 50 MW Solar Connect 2018
(2) Added in 2019
(3) Added in 2020
(4) Added in 2020 and 2022
(5) 2016-2054 PVRR

Figure 1.5-3 below shows the total MW of wind and utility scale solar included in Alternative Plans 1, 2, 3, and 4 for the time period from 2017-2040. In evaluating the costs and benefits of renewable resource additions during the RAP, all existing renewable resources were included in the model only for the duration of their existing lives, which would be the term of the current PPA in most instances. This approach better ensures that the costs and benefits of renewables added during the RAP are not negatively influenced by arbitrary assumptions regarding which, if any, existing renewables will: 1) be operational beyond the term of their current PPAs, and 2) would be offered back to Public Service rather than offered to another electric utility in the state.

Figure 1.5-3 RAP Additions Analysis - Renewables to 2040

		Total MW of operating wind and utility scale solar							
		Baseline		600 MW 100% PTC Wind		600 MW 100% PTC Wind + 400 MW 80% PTC Wind		600 MW 100% PTC Wind + 400 MW 30% ITC Solar	
		Plan 1 Wind	Plan 1 Solar	Plan 2 Wind	Plan 2 Solar	Plan 3 Wind	Plan 3 Solar	Plan 4 Wind	Plan 4 Solar
RAP	2017	2,525	254	2,525	254	2,525	254	2,525	254
	2018	2,525	303	3,125	303	3,125	303	3,125	303
	2019	2,363	301	2,963	301	2,963	301	2,963	301
	2020	2,363	300	2,963	300	3,363	300	2,963	500
	2021	2,363	298	2,963	298	3,363	298	2,963	498
	2022	2,363	297	2,963	297	3,363	297	2,963	697
	2023	2,363	295	2,963	295	3,363	295	2,963	695
	2024	2,363	293	2,963	293	3,363	293	2,963	693
	2025	2,363	292	2,963	292	3,363	292	2,963	692
	2026	2,303	290	2,903	290	3,303	290	2,903	690
	2027	2,273	289	2,873	289	3,273	289	2,873	689
	2028	1,727	281	2,327	281	2,727	281	2,327	681
	2029	1,726	279	2,326	279	2,726	279	2,326	679
	2030	1,704	278	2,304	278	2,704	278	2,304	678
	2031	1,701	260	2,301	260	2,701	260	2,301	660
	2032	1,452	258	2,052	258	2,452	258	2,052	658
	2033	1,253	202	1,853	202	2,253	202	1,853	602
	2034	1,250	201	1,850	201	2,250	201	1,850	601
	2035	1,101	200	1,701	200	2,101	200	1,701	600
	2036	1,101	199	1,701	199	2,101	199	1,701	599
	2037	843	198	1,443	198	1,843	198	1,443	598
	2038	450	152	1,050	152	1,450	152	1,050	552
	2039	448	151	1,048	151	1,448	151	1,048	551
	2040	241	150	841	150	1,241	150	841	550

Note that the MW values listed for renewable resources in Figure 1.5-2 are nameplate ratings. The level of firm capacity equivalent that such resources provide to the system (i.e., their ELCC) is considerably less than their nameplate rating. As a result, it can take several hundred MWs of renewable resource additions to provide the same amount of firm capacity as the 205 MW large CT. Also note that the MW size of the of the large CTs and the 2x1 CCs will often result in more generation capacity being added to the system than what is needed.

General Observations on PVRR Cost

The results of the RAP additions analysis in Figure 1.5-2 indicate that under base assumptions the combination of combustion turbines and renewable resources are a lower cost option for meeting the RAP needs that is an all-gas portfolio. Additional wind at both the 100% PTC level and 80% PTC level shows reduced costs compared to the all-gas alternative plan 1 Case ($440 million and $590 million less costs respectively). Similarly, when utility-scale solar that qualifies for the full 30% ITC is added in Alternative Plan 4, it reduces that plan cost by $130 million compared to Alternative Plan 2 which includes only wind.

The remainder of this section includes additional discussion regarding various aspects of these four alternative plans as well as sensitivity analyses of these plans under different natural gas price assumptions and different levels of electric sales. These aspects of the alternative plans are discussed below in the following order:

1. PTC
2. ITC
3. Carbon Emissions
4. RESA Impacts
5. Gas Price Sensitivities (low and high prices)
6. Sales Sensitivities (low and high sales)

PTC Analysis

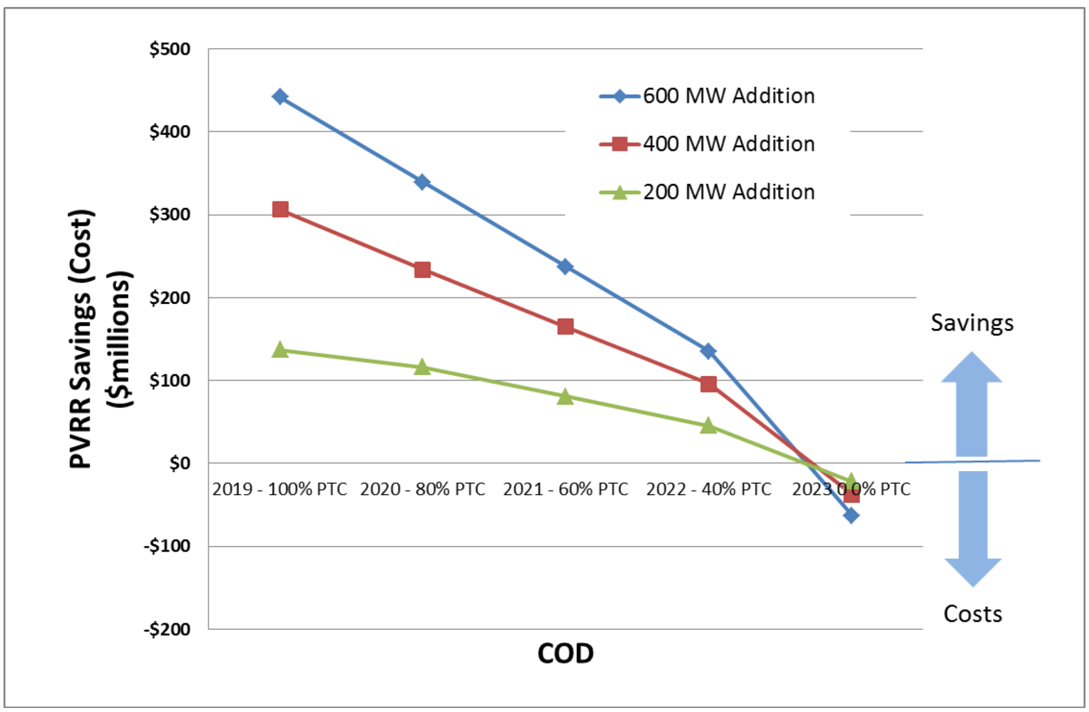
As part of the analysis of alternative plans, Public Service evaluated the system costs and benefits associated with adding wind resources that qualify for 100% of the PTC versus the lower levels of qualification (i.e., 80%, 60%, 40% and 0%). The analysis also involved examining two lesser levels of wind (400 MW and 200 MW) as well a range of in-service dates that reflect a reasonable relationship between these variables (i.e., PTC level and in-service date). A total of fifteen individual model runs were performed to examine the various combinations of wind MW's, PTC qualification levels, and wind in-service year. Table 1.5-3 summarizes the combinations that were evaluated.

Table 1.5-3 Analysis of PTC level and Wind In-Service Year

Wind Level	In-Service 2019	In-Service 2020	In-Service 2021	In-Service 2022	In-Service 2023
600 MW	100%	80%	60%	40%	0%
400 MW	100%	80%	60%	40%	0%
200 MW	100%	80%	60%	40%	0%

The analysis was performed by taking Alternative Plan 2 and altering the 600 MW of wind in that plan to reflect the representations in Table 1.5-3.[21] This resulted in fifteen separate plans each of which was evaluated in Strategist to produce a PVRR value that could be compared with that of alternative plan 1. Figure 1.5-4, includes a graphical comparison of the results of this analysis.

Figure 1.5-4 PVRR Comparison of Table 1.5-3 Combinations



PTC Analysis Observations

Figure 1.5-4 illustrates how customer benefits are maximized when the 600 MW of wind are acquired at the 100% level of PTC qualification. The figure shows a clear

[21] Alteration of the 600 MW wind resource was done by holding the $/kw cost of that 600 MW facility constant and adjusting the facility MW, PTC level and in-service date.

correlation between the higher level of wind, higher levels of PTC qualification, and higher levels of customer savings. At the 100% level of PTC, the relationship between wind MW and PVRR savings is for the most part linear, with 400 MW providing roughly two-thirds the level of PVRR savings that 600 MW provides, and 200 MW providing one third the value of 600 MW. Not surprisingly, the PVRR savings erode considerable as the level of PTC eligibility (i.e., 80%, 60%, 40%) declines. At the 0% PTC level (i.e., no PTC) all three MW levels of wind no longer provide PVRR savings but instead add cost to the system (shown as negative savings). The general take-away from this analysis is that customer savings are maximized with the addition of the maximum amount of wind considered, the 600 MW of 100% PTC wind.

ITC Analysis

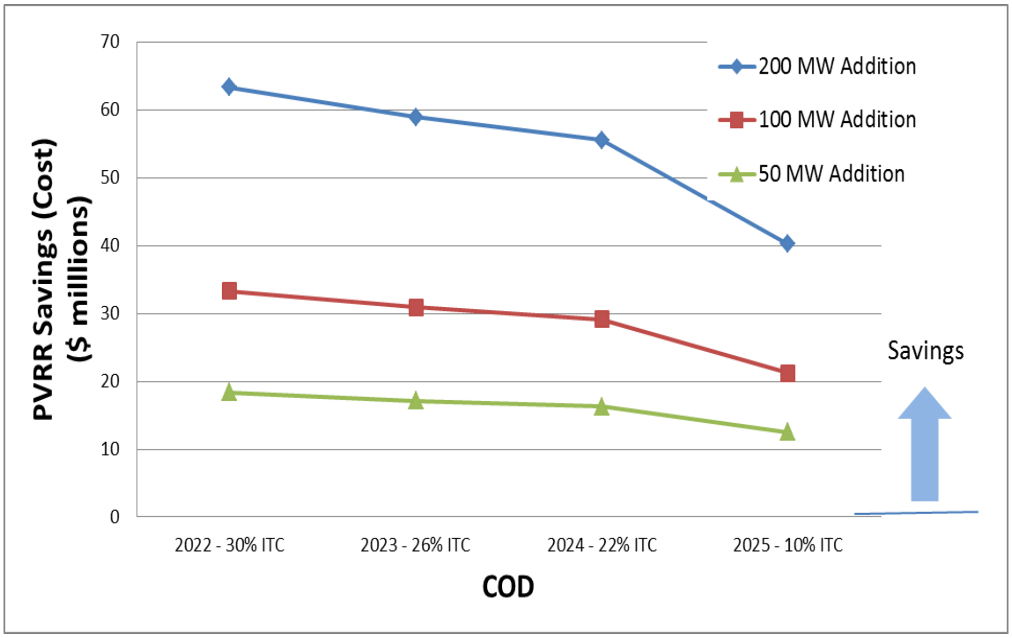
Similar to the PTC analysis discussed above, Public Service evaluated the economic value associated with solar resources that qualify for the 30% ITC versus the lower levels of qualification (i.e., 26%, 22%, and 10%) specified in the Consolidated Appropriations Act, 2016. This analysis examined three levels of utility scale solar, 200 MW, 100 MW, and 50 MW as well a range of in-service dates that align with the level of ITC. A total of twelve individual model runs were performed to examine the various combinations of solar MW's, ITC qualification levels and solar in-service year. Table 4 summarizes the combinations that were evaluated.

Table 1.5-4 Analysis of ITC level and Solar In-Service Year

Solar Level	In-Service 2022	In-Service 2023	In-Service 2024	In-Service 2025
200 MW	30%	26%	22%	10%
100 MW	30%	26%	22%	10%
50 MW	30%	26%	22%	10%

The analysis was performed by taking Alternative Plan 1 and individually adding the twelve solar representations in Table 1.5-4. The costs and benefits of each combination of solar MW, ITC level, and solar in-service year can be represented by the PVRR metric that is produced from a Strategist model run of each combination listed in Table 1.5-4. Figure 1.5-5, includes a graphical comparison of the PVRR savings associated with each of the twelve combinations in Table 1.5-4.

Figure 1.5-5 – PVRR Comparison of Table 1.5-4 Combinations



ITC Analysis Observations

Figure 1.5-5 shows a clear correlation between a higher MW level of solar addition and higher levels of customer savings. The relationship between PVRR savings associated with 50 MW and 100 MW solar additions being mostly linear, with 100 MW providing roughly twice the PVRR savings as does 50 MW. Going from 100 MW to 200 MW shows a moderate level of diminishing returns in that the savings don't quite double as was the case going from 50 MW to 100 MW. Figure 1.5-5 also illustrates an erosion of PVRR savings as the level of ITC eligibility (i.e., 30%, 26%, 22%, 10%) declines. This erosion of savings is less pronounced than what happens with the PTC.

Carbon Emission Analysis

At the federal level, the U.S. Supreme Court, on February 9, 2016, stayed implementation of the Clean Power Plan pending judicial review. At the state level, the State of Colorado has yet to complete its work to develop a plan and associated rules that detail how the state will comply with EPA's final CPP rules. As a result, all information and analysis presented herein regarding CO_2 and CPP are intended to provide general indications of how the different levels of renewables that are contained in the alternative plans might better position the Company to meet the levels of CO_2 reductions contained in EPA's final rules. By providing this information the Company is not attempting to represent with any level of certainty that a particular alternative plan will or will not comply with the State of Colorado's CPP implementation plan, given that the specifics of that state plan have not yet been developed.

Recognizing the limitations noted above, information pertaining to estimated levels of CO_2 emissions and renewable energy generation of the alternative plans is summarized in Table 1.5-5.

Table 1.5-5 RAP Additions CO_2 and Renewable Generation

Total System CO2 Emissions (Million Short Tons)															
Alt Plan	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	22.9	23.2	22.0	22.1	23.0	23.3	23.3	22.5	22.6	22.6	22.8	23.1	24.0	24.1	24.3
2	22.9	23.2	21.7	20.7	21.7	21.9	21.9	21.5	21.7	21.7	21.9	22.2	22.8	22.9	23.1
3	22.9	23.2	21.7	20.7	20.8	21.1	21.1	20.6	20.8	20.9	21.1	21.4	22.4	22.6	22.7
4	22.9	23.2	21.7	20.7	21.4	21.6	21.3	20.9	21.1	21.1	21.3	21.6	22.6	22.8	23.0
CPP Affected Unit CO2 Emissions (Million Short Tons)															
1	22.6	22.9	21.5	21.4	22.3	22.2	22.1	21.1	21.1	21.1	21.2	21.4	21.3	21.3	21.3
2	22.6	22.9	21.2	20.2	21.1	21.2	21.1	20.5	20.5	20.5	20.6	20.9	20.8	20.8	20.8
3	22.6	22.9	21.2	20.2	20.3	20.4	20.4	19.7	19.8	19.8	20.0	20.2	20.6	20.7	20.8
4	22.6	22.9	21.2	20.2	20.9	20.9	20.7	20.0	20.1	20.1	20.2	20.5	20.9	20.9	21.0
Total Post 2012 DSM EE and Renewable Generation (1000 GWh)															
1	3.4	3.9	4.4	4.7	5.1	5.6	5.9	6.2	6.5	6.8	7.0	7.2	7.5	7.4	7.3
2	3.4	3.9	5.0	7.0	7.4	7.9	8.2	8.5	8.8	9.0	9.3	9.5	9.8	9.7	9.6
3	3.4	3.9	5.0	7.0	8.9	9.3	9.6	9.9	10.2	10.5	10.8	11.0	11.2	11.2	11.1
4	3.4	3.9	5.0	7.0	7.9	8.4	9.2	9.5	9.8	10.1	10.4	10.6	10.8	10.7	10.7
General CO2 Emission Rate (lb/MWh) (1)															
1	1,628	1,604	1,505	1,455	1,472	1,432	1,409	1,361	1,350	1,336	1,322	1,313	1,306	1,306	1,308
2	1,628	1,604	1,477	1,356	1,375	1,341	1,321	1,273	1,264	1,251	1,240	1,232	1,226	1,227	1,230
3	1,628	1,604	1,477	1,356	1,303	1,276	1,259	1,215	1,206	1,196	1,186	1,179	1,171	1,173	1,175
4	1,628	1,604	1,477	1,356	1,354	1,321	1,283	1,236	1,228	1,215	1,204	1,197	1,185	1,187	1,189

Notes:
1) Calculated by converting the CPP Affected Unit CO2 Emissions from tons to lbs, then dividing by the sum of 1) Total Post 2012 DSM EE and Renewable Generation in MWh and 2) CPP Affected unit generation in MWh

Two categories of CO_2 emissions are provided in Table 1.5-5, including: 1) total system CO_2, and 2) CPP affected unit CO_2 emissions. Total system CO_2 emissions represent the annual summation of CO_2 emitted within the Strategist model from all fossil-fired generation resources used by the model to serve the forecast of Public Service electric system sales. This includes all Company owned coal and gas-fired generators regardless of installation date as well as all PPAs sourced from either coal or gas-fired generation regardless of PPA execution date.

CPP-affected unit CO_2 emissions are a subset of the total system CO_2 emissions and represent the annual summation of CO_2 emitted within the Strategist model from all fossil-fired generation resources that were identified as “affected units” in the EPA’s Final Clean Power Plan rules that were published in the Federal Register on

October 23, 2015. Additional details about the assumed CPP affected units utilized for purposes of this analysis see Section 2.4 of ERP Volume 2.

The total GWh values of DSM EE and renewable generation contained in Table 1.5-5 are comprised of the following components:

- 75% of all DSM EE achievements from 2012-2020
- 100% of all DSM EE achievements beyond 2020
- 50% of all DG solar MWh installed post 12/31/2012
- 100 % of all utility scale renewables installed post 12/31/2012

<u>Carbon Emission Analysis Observations</u>

Absent the details that a state CPP compliance plan would provide, the Company is limited in its ability to provide a substantive discussion that addresses how the various alternative plans might ultimately enable Public Service to comply with the CPP carbon reduction targets through the RAP. Nevertheless, the alternative plan analysis does provide a general indication that Public Services past and continued efforts in the area of DSM and customer choice programs coupled with our plan to add the Rush Creek Wind Project[22] under Rule 3660(h), and possibly additional wind and solar through this ERP, will further enhance the Company's position to address future public policy regulations regarding carbon.

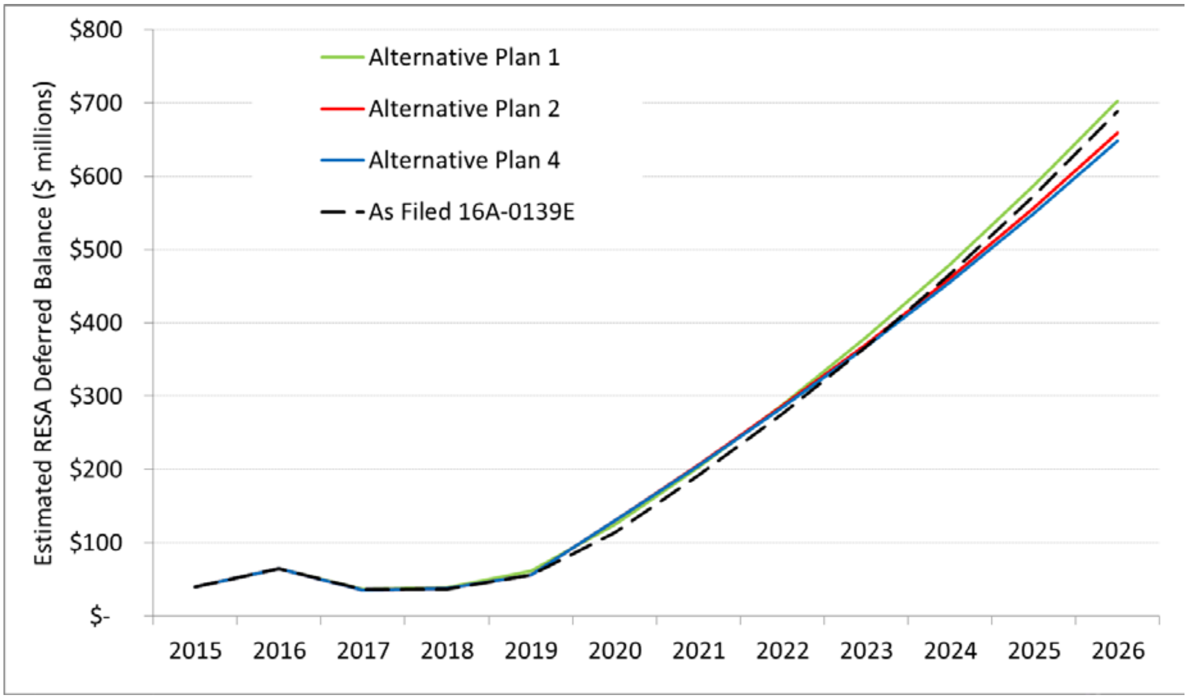
<u>RESA Deferred Balance Analysis</u>

In addition to estimating the planning period PVRR deltas between the four alternative plans, the Company also used Strategist to develop estimates of how the increasing levels of renewable resources contained in the alternative plans would impact the RESA deferred balance. Currently that balance is estimated to be in the neighborhood of a positive $44 million.[23]

[22] On May 13, 2016 in Proceeding No. 16A-0117E, Public Service filed an application with the CPUC requesting a CPCN to construct and own the 600 MW Rush Creek Wind Project.

[23] See the 2017 RE Plan for information regarding the RESA balance.

Figure 1.5-6 RAP Additions and RESA Deferred Balance



Additional Sensitivity Analysis

Public Service also examined the robustness of the plans by altering the level of sales, and natural gas prices that were input into the Strategist model.[24] Table 1.5-6 provides a summary of these sensitivity assumptions.

Table 1.5-6 Additional Sensitivity Assumptions

Assumption	Sensitivity Value
Low Gas Prices	Assumes growth rate 50% lower than base case after 2017
High Gas Prices	Assumes growth rate 50% higher than base case after 2017
Low Sales	15th percentile probability based on Monte Carlo simulation
High Sales	85th percentile probability based on Monte Carlo simulation

Gas Price Sensitivity Analysis

The sensitivity analyses for low and high gas prices were performed by rerunning each alternative plan for years 2016-2054 in Strategist with the only change being

[24] 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.

different gas price assumptions[25]. No changes were made to the timing or mix of existing resources or generic resources additions that were included in each plan. As a result, each plan was in essence re-priced using different future gas price assumptions. Maintaining the same mix and timing of generation resources in this manner ensures that the PVRR differences between the plans are driven by the characteristics of the resources contained in the different alternative plans. Table 1.5-7 summarizes the results of the gas price sensitivity analysis of the plans. All PVRR values are rounded to the nearest $10 million.

Table 1.5-7 RAP Additions Gas Price Sensitivity Analysis

RAP Renewable Resource Additions	Alternative Plan			
	1	**2**	**3**	**4**
Baseline Case/Alternative Plan 1	-	-	-	-
600 MW 100% PTC Wind	-	600 MW	600 MW	600 MW
400 MW 80% PTC Wind	-	-	400 MW	-
400 MW 30% ITC Solar	-	-	-	400 MW
Total RAP additional Renewables	**0 MW**	**600 MW**	**1,000 MW**	**1,000 MW**
RAP Non-Renewable Additions				
Large Combustion Turbine (CT)	2 CTs 410 MW	4 CTs 820 MW	4 CTs 820 MW	3 CTs 615 MW
2x1 Combined Cycle (2x1 CC)	1 CCs 700 MW	-	-	-
Total RAP additional Non-Renewables	**1110 MW**	**820 MW**	**820 MW**	**615 MW**

2016-2054 PVRR Deltas from Baseline ($M)

Low Gas Prices	$0	($210)	($210)	($190)
Base Gas Prices	$0	($440)	($590)	($570)
High Gas Prices	$0	($740)	($1,100)	($1,080)

Gas Price Sensitivity Analysis Observations

Under low gas prices, 100% PTC wind continues to provide savings of over $200 million. Both 80% PTC wind and 30% ITC solar, however, provide essentially no additional savings to the system (i.e., in addition to what 100% PTC wind provides) under a low gas price future. Not surprisingly, under high gas prices, both levels of PTC wind show considerable savings as does the 30% level of ITC solar.

[25] Wind integration and solar integration costs are a function of natural gas prices and therefore were appropriately adjusted to align with each gas price sensitivity.

Sales Forecast Sensitivity Analysis

The low and high sales sensitivity analyses required that a new "base model" be developed within which the four 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 are needed in order to serve the different levels of energy sales and demand contained in the low and high sales forecasts. Tables 1.5-8 and 1.5-9 summarize the results of these low and high sales forecasts sensitivities.

Table 1.5-8 RAP Additions Low Sales Sensitivity Analysis

RAP Renewable Resource Additions	Alternative Plan			
	1	2	3	4
Baseline Case/Alternative Plan 1	-	-	-	-
600 MW 100% PTC Wind	-	600 MW	600 MW	600 MW
400 MW 80% PTC Wind	-	-	400 MW	-
400 MW 30% ITC Solar	-	-	-	400 MW
Total RAP additional Renewables	**0 MW**	**600 MW**	**1,000 MW**	**1,000 MW**
RAP Non-Renewable Additions				
Large Combustion Turbine (CT)	1 CTs 205 MW	-	-	-
2x1 Combined Cycle (2x1 CC)	-	-	-	-
Total RAP additional Non-Renewables	**205 MW**	**0 MW**	**0 MW**	**0 MW**

2016-2054 PVRR Deltas from Baseline ($M)

Low Gas Prices	$0	($130)	($50)	($60)
Base Gas Prices	$0	($380)	($450)	($440)
High Gas Prices	$0	($720)	($1,030)	($1,010)

Table 1.5-9 RAP Additions High Sales Sensitivity Analysis

RAP Renewable Resource Additions	Alternative Plan			
	1	2	3	4
Baseline Case/Alternative Plan 1	-	-	-	-
600 MW 100% PTC Wind	-	600 MW	600 MW	600 MW
400 MW 80% PTC Wind	-	-	400 MW	-
400 MW 30% ITC Solar	-	-	-	400 MW
Total RAP additional Renewables	**0 MW**	**600 MW**	**1,000 MW**	**1,000 MW**
RAP Non-Renewable Additions				
Large Combustion Turbine (CT)	4 CTs 820 MW	5 CTs 1025 MW	5 CTs 1025 MW	4 CTs 820 MW
2x1 Combined Cycle (2x1 CC)	1 CCs 700 MW	1 CCs 700 MW	1 CCs 700 MW	1 CCs 700 MW
Total RAP additional Non-Renewables	**1520 MW**	**1725 MW**	**1725 MW**	**1520 MW**

2016-2054 PVRR Deltas from Baseline ($M)

Low Gas Prices	$0	($210)	($230)	($210)
Base Gas Prices	$0	($480)	($650)	($620)
High Gas Prices	$0	($890)	($1,250)	($1,220)

Sales Forecast Sensitivity Analysis Observations

Under low sales and base gas prices, alternative plans 2, 3, and 4 continued to show savings but at levels 15% to 30% lower than those shown under base sales. 100% PTC wind showed the least reduction in savings at 15%. Both 80% PTC wind and 30% ITC solar showed a reduction in savings of about 30%. Under low sales and low gas prices, alternative plans 2, 3, and 4 continued to show savings but at considerable lower levels.

In a high sales environment, alternative plans 2, 3, and 4 all showed less sensitivity to changes in gas prices than those observed under low sales.

Post-RAP Additions Analysis - Alternative Plans

As illustrated earlier in Figure 1.5-1, one alternative plan from the "RAP Additions Analysis" discussed above was selected to serve as the foundation upon which alternative plans that focus on renewable additions beyond the RAP were built. Public Service selected alternative plan 4 to serve as this foundation.

Table 1.5-10 Post-RAP Additions Analysis

Post-RAP Renewable Adds to Alternative Plan 4	Alternative Plan (1)			
	4A	4B	4C	4D
Minimum RES Compliance	✓			
Maintain ~3,100 MW Wind		✓		
Measured Renewable Additions			✓	
High Renewable Additions				✓
PVRR Delta From Plan 4A ($M) (2)	**$0**	**$220**	**$150**	**$310**

Notes:
(1) Solar Rewards & Community at ~106 MW (DC) annually in all plans A, B, C, D
(2) 2016-2054 PVRR

Table 1.5-10 summarizes the PVRR cost delta's associated with different levels of post-RAP renewable additions to alternative plan 4. PVRR deltas are measured relative to plan 4A. So for example, the PVRR of plan 4B is $220 million higher than the PVRR of plan 4A. While not shown in Table 1.5-10, the PVRR of alternative plan 4A is approximately $40 million more than plan 4. An estimate of the PVRR delta between plan 4 and each of the plans in Table 1.5-10 can therefore be estimated by adding $40 million to each of the PVRRs shown in the table.

Table 1.5-11 below shows the total MW of wind and utility scale solar included in alternative plans 4A, 4B, 4C and 4D for the time period from 2017-2040. In the analysis of Post-RAP renewable additions the cost of the wind and solar PV resources are based on an assumption assume 0% PTC for wind and 10% ITC for solar as indicted earlier in Table 1.5-2.

Table 1.5-11 Post-RAP Additions Analysis - Renewables to 2040

		Total MW of operating wind and utility scale solar							
		Minimum RES Compliance		Maintain ~3,100 MW Wind		Measured Additions		High Renewables	
		4A Wind	4A Solar	4B Wind	4B Solar	4C Wind	4C Solar	4D Wind	4D Solar
RAP	2017	2,525	254	2,525	254	2,525	254	2,525	254
RAP	2018	3,125	303	3,125	303	3,125	303	3,125	303
RAP	2019	3,119	301	3,119	301	3,119	301	3,119	301
RAP	2020	2,963	500	2,963	500	2,963	500	2,963	500
RAP	2021	2,963	498	2,963	498	2,963	498	2,963	498
RAP	2022	2,963	697	2,963	697	2,963	697	2,963	697
RAP	2023	2,963	695	2,963	695	2,963	695	2,963	695
	2024	2,963	693	3,163	693	3,163	693	3,163	893
	2025	2,963	692	3,163	692	3,163	792	3,363	1,092
	2026	2,963	690	3,163	690	3,363	890	3,563	1,090
	2027	2,873	689	3,073	689	3,473	889	3,473	1,289
	2028	2,327	681	3,127	681	3,127	1,131	3,327	1,581
	2029	2,326	679	3,126	679	3,126	1,279	3,326	1,779
	2030	2,304	678	3,104	678	3,104	1,378	3,504	1,778
	2031	2,301	660	3,101	660	3,101	1,460	3,501	1,860
	2032	2,052	658	3,252	658	3,252	1,458	3,652	1,858
	2033	1,853	602	3,253	702	3,453	1,502	3,853	1,902
	2034	1,850	601	3,250	701	3,450	1,501	3,850	1,901
	2035	1,701	600	3,101	700	3,701	1,600	4,101	2,000
	2036	1,701	599	3,101	699	3,701	1,599	4,101	1,999
	2037	1,443	598	3,243	698	3,843	1,898	4,243	2,298
	2038	1,050	552	3,250	702	3,850	1,852	4,250	2,252
	2039	1,248	851	3,248	701	3,848	2,151	4,248	2,551
	2040	1,441	850	3,241	700	3,841	2,150	4,241	2,550

The MW values shown in Table 1.5-11 are cumulative of: 1) the existing wind and solar on the system; 2) the renewable additions during the RAP that are contained in alternative plan 4; and 3) the renewable additions added to alternative plan 4 in years after the RAP.

General Observations on PVRR Cost

The results of the Post-RAP additions analysis summarized in Table 1.5-10 show that adding 0% PTC wind and 10% ITC solar beyond the RAP could result in moderate cost increases to the Public Service system (compared to plan 4A). These results emphasize the economic value of the Company’s plans to pursue capturing the higher levels of PTC and ITC for customers in this ERP.

The remainder of this section includes additional discussion regarding various aspects of these four Post-RAP alternative plans as well as sensitivity analyses of these plans under different natural gas price assumptions. These aspects of the alternative plans are discussed below in the following order:

1. Carbon Emissions
2. RESA Impacts
3. Gas Price Sensitivities (low and high prices)

Carbon Emission Analysis

As discussed earlier, all information and analysis presented herein regarding CO_2 emissions and the CPP are intended to provide general indications of how different levels of renewables beyond the RAP contained in the alternative plans might position the Company to meet the general levels of CO_2 reductions set forth in the CPP. By providing this information the Company is not attempting to represent with any level of certainty which alternative plans or other actions would ultimately result in compliance with the CPP.

Table 1.5-12 Post-RAP CO_2 and Renewable Generation

Alt Plan	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total System CO2 Emissions (Million Short Tons)															
4A	22.9	23.2	21.7	20.7	21.4	21.6	21.3	20.9	21.1	21.1	21.3	21.6	22.6	22.8	23.0
4B	22.9	23.2	21.7	20.7	21.4	21.6	21.3	20.9	20.6	20.7	20.9	21.2	20.9	21.1	21.3
4C	22.9	23.2	21.7	20.7	21.4	21.6	21.3	20.9	20.6	20.5	20.2	20.0	20.2	20.2	20.2
4D	22.9	23.2	21.7	20.7	21.4	21.6	21.3	20.9	20.3	19.7	19.4	19.4	19.1	19.0	18.7
CPP Affected Unit CO2 Emissions (Million Short Tons)															
4A	22.6	22.9	21.2	20.2	20.9	20.9	20.7	20.0	20.1	20.1	20.2	20.5	20.9	20.9	21.0
4B	22.6	22.9	21.2	20.2	20.9	20.9	20.7	20.0	19.7	19.8	19.9	20.2	19.7	19.8	19.9
4C	22.6	22.9	21.2	20.2	20.9	20.9	20.7	20.0	19.7	19.6	19.3	19.2	19.2	19.1	19.1
4D	22.6	22.9	21.2	20.2	20.9	20.9	20.7	20.0	19.5	18.9	18.7	18.7	18.2	18.1	17.9
Total Post 2012 DSM EE and Renewable Generation (GWh)															
4A	3.4	3.9	5.0	7.0	7.9	8.4	9.2	9.5	9.8	10.1	10.4	10.6	10.8	10.7	10.7
4B	3.4	3.9	5.0	7.0	7.9	8.4	9.2	9.5	10.5	10.8	11.1	11.3	13.7	13.7	13.6
4C	3.4	3.9	5.0	7.0	7.9	8.4	9.2	9.5	10.5	11.1	12.3	13.3	14.9	15.2	15.4
4D	3.4	3.9	5.0	7.0	7.9	8.4	9.2	9.5	11.1	12.6	13.6	14.3	16.8	17.2	17.9
General CO2 Emission Rate (lb/MWh) (1)															
4A	1,628	1,604	1,477	1,356	1,354	1,321	1,283	1,236	1,228	1,215	1,204	1,197	1,185	1,187	1,189
4B	1,628	1,604	1,477	1,356	1,354	1,321	1,283	1,236	1,199	1,188	1,178	1,171	1,089	1,092	1,095
4C	1,628	1,604	1,477	1,356	1,354	1,321	1,283	1,236	1,199	1,178	1,131	1,097	1,049	1,038	1,032
4D	1,628	1,604	1,477	1,356	1,354	1,321	1,283	1,236	1,180	1,119	1,082	1,057	977	960	937

Notes:
1) Calculated by converting the CPP Affected Unit CO2 Emissions from tons to lbs, then dividing by the sum of 1) Total Post 2012 DSM EE and Renewable Generation in MWh and 2) CPP Affected unit generation in MWh

The categories of CO_2 emissions and DSM EE and renewable energy generation provided in Table 1.5-7 are the same as those provided earlier in Table 1.5-5. In addition, the total GWh values of DSM EE and renewable generation contained in Table 1.5-7 are comprised of the following components;

- 75% of all DSM EE achievements from 2012-2020
- 100% of all DSM EE achievements beyond 2020
- 50% of all DG solar MWh installed post 12/31/2012
- 100% of all utility scale renewables installed post 12/31/2012

Carbon Emission Analysis Observations

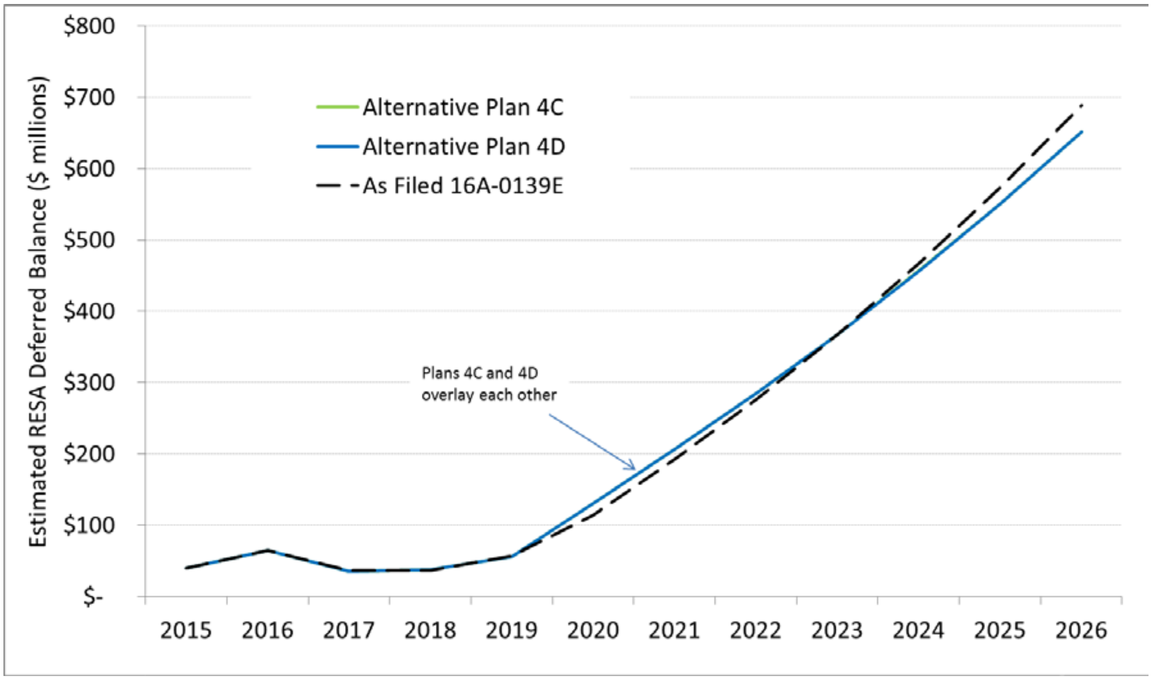
As stated previously, absent the details that a state CPP compliance plan would provide, the Company is limited in its ability to provide a substantive discussion that addresses how the various Post-RAP alternative plans might position Public Service to comply with the CPP carbon reduction targets through 2030. The Post-RAP alternative plan analysis does, however, provide a general indication that 1) RAP additions of the 600 MW Rush Creek Wind Project and 400 MW of solar, combined with 2) a range of Post-RAP renewable additions represented in plans 4A, 4B, 4C, ad 4D, will further enhance the Company's position to address future public policy regulations regarding carbon.

RESA Deferred Balance Analysis

The Company also used Strategist to develop estimates of how the increasing levels of renewable resources contained in alternative plans 4C and 4D could impact the RESA deferred balance. Currently that balance is estimated to be in the neighborhood of a positive $44 million.[26] Figure 1.5-7 shows the estimated post-RAP RESA deferred balance.

[26] See the 2017 Renewable Energy Plan for information regarding the RESA balance.

Figure 1.5-7 Post-RAP RESA Deferred Balance



Gas Price Sensitivity Analysis

The sensitivity analyses for low and high gas prices were performed by rerunning each alternative plan for years 2016-2054 in Strategist with the only change being different gas price assumptions[27]. Figure 1.5-13 summarizes the results of this analysis.

[27] Wind integration and solar integration costs are a function of natural gas prices and therefore were appropriately adjusted to align with each gas price sensitivity.

Table 1.5-13 Post-RAP Gas Price Sensitivity Analysis

Post-RAP Renewable Adds to Alternative Plan 4	Alternative Plan			
	4A	4B	4C	4D
Minimum RES Compliance	✓			
Maintain ~3,100 MW Wind		✓		
Measured Renewable Additions			✓	
High Renewable Additions				✓
2016-2054 PVRR Deltas from Baseline ($M)				
Low Gas Prices	$0	$840	$1,110	$1,490
Base Gas Prices	$0	$220	$150	$310
High Gas Prices	$0	($780)	($1,360)	($1,570)

Gas Price Sensitivity Analysis Observations

Under low gas prices 100% PTC wind continues to provide savings of over $200 million. Both 80% PTC wind and 30% ITC solar however provide essentially no savings to the system under low gas prices. Not surprisingly, under high gas prices, both levels of PTC wind show considerable savings as does the 30% level of ITC solar.

1.6 RESOURCE ACQUISITION PLAN

The Company proposes a Phase II competitive acquisition process to acquire additional generation resources. Detailed descriptions of the Company's proposal for soliciting and evaluating proposals are included in Section 2.9 of ERP Volume 2. A summary of the Company's proposal includes:

- The Company would conduct the bulk of its economic analyses using the Strategist model tool.
- All generation technologies other than coal-fired generation would be deemed eligible technologies.
- Demand-side resources would not compete.
- The Company does not propose any carve outs or set-asides for any specific generation technologies including Section 123 or Section 124 resources. To the extent the Commission desires to see portfolios from the Phase II process that contains Section 123 Resources the Commission should direct the Company to do so in its Phase I order.
- The Company proposes that generators sized larger than 100 kW compete.[28]
- The Company has developed a distinct Company Ownership RFP to encourage the sale of existing and/or newly-constructed generation for Company ownership.

<u>Phase II Capacity Need</u>

The Company proposes an 8-year resource acquisition period. If power supply proposals are to serve a portion of the 8-year RAP need, they must begin commercial operation prior to the 2023 summer peak in order to be eligible for consideration in the Phase II acquisition process. Thus, all power supply proposals must offer a commercial operations date no later than May 1, 2023.

The actual RAP capacity need to be met through the competitive acquisition will be impacted by the Commission's future decisions in other proceedings as well as any changes to the Company's load forecast. Current issues that could impact the ultimate level of generation capacity to be acquired through the Phase II process include:

[28] Unless otherwise indicated, the terms MW and MWh refer to MW_{AC} and MWh_{AC}.

2017 RE Plan [Proceeding No. 16A-0139E]

The Company filed its 2017 RE Plan on February 29, 2016. That plan proposed Solar*Rewards and Solar*Rewards Community programs designed to acquire additional retail renewable distributed generation ("Retail DG") for the 2017-2019 calendar years. Consistent with FERC decisions,[29] the Company includes behind-the-meter generation (e.g., Retail DG) in its portfolio of Net Dependable Generation Capacity resources on its loads and resources table ("L&R table") along with all other solar generation resources.[30]

Consistent with prior practice, the Company projects the most-recently-filed acquisition levels of customer choice solar forward on its L&R table through the ERP RAP. In its 2017 RE Plan filing, the Company proposed programs to acquire a maximum of ~106 MW_{DC} of additional customer choice solar during 2019. In addition, the Company's current L&R table also assumes additional Retail DG each year from behind-the-meter solar generation that interconnects without the benefit of Solar*Rewards incentives. With an assumption of ~105 MW_{DC} annual addition to continue for an additional four years, the Company will have added over 600 MW_{DC} of customer choice solar between 2017 and the end of 2023.[31] Depending upon ELCC assumptions, the Company's need for additional generation capacity in 2023 could be reduced by up to 215 MW.[32] If the Commission ultimately approves a higher or lower rate of customer choice solar acquisition in the 2017 RES Plan proceeding, then the Company will reflect that decision in its resource need calculation for the Phase II acquisition process.

Solar*Connect [Proceeding No. 16A-0055E]

The Company filed for approval of its Solar*Connect program on January 27, 2016. In that application, the Company sought approval to acquire generation from an additional solar generator(s) up to 50 MW. If that acquisition is approved, this additional generator(s) would reduce the 2023 need by between ~18 and 26 MW depending upon the location of the generator(s) and tracking capabilities.[33]

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[29] See, e.g., FERC Order on Rehearing in Dockets No. ER08-394-004 and ER08-394-005 (February 19, 2009) at ¶15.
[30] All solar generation resources are carried on the L&R table at an ELCC rate based on the Company's most recent solar ELCC study.
[31] 755 MW_{DC} = 291 MW_{DC} (from Table No. 1 in Attachment RLK-1 in the 2017 RES Plan.) + 4 years * 116 MW_{DC}/year.
[32] See Table 1.4-2
[33] The Company's most recent solar ELCC study shows a minimum rate of 37% and a maximum rate of 53%.

2017 DSM Strategic Issues [Proceeding No. 13A-0686EG]

The Company's current L&R incorporates the Commission's Decision in the 2013 DSM Strategic Issues proceeding setting out the future peak load reductions the Company was to assume in this ERP filing.[34] The Company is to file its 2017 DSM Strategic Issues proceeding no later than March 31, 2017. Should the Commission's decision in that proceeding be issued in advance of a Phase II acquisition process and should the Commission again determine the future peak load reductions that the Company is to assume, the Company would include those determinations in its L&R table which may increase or decrease the need to be met through a Phase II process.

600 MW Rush Creek Wind Project [Proceeding No. 16A-0117E]

On May 13, 2016, the Company filed an application to construct and own the 600 MW Rush Creek Wind Project pursuant to C.R.S. § 40-2-124(1)(f)(I) and Commission Rule 3660(h). Based on the Company's most recent wind ELCC study, this 600 MW of additional wind would reduce the RAP period need by 49 MW.

Minimum Bid Size

While 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, Rule 3615(a)(III) allows the Company to acquire generation resources no larger than 30 MW outside of an approved ERP. However, in order to more fully consider and evaluate all available power supply options available to the Company in this ERP, Public Service proposes that supply-side electric generation technologies with a nameplate electric rating greater than 100 kW would be eligible for consideration. Such a minimum project size will allow the Company to determine if the credits afforded to small, supply-side resources interconnecting at distribution voltages can overcome typically lower-cost supplies from larger generation projects employing similar generation technologies. Minimum project sizes greater than 100 kW will also allow the Company to evaluate other proposed technologies that may not currently scale to larger sizes, such as Section 123 proposals.

In prior Phase II processes, the Company had established a higher minimum project size than the 100 kW level proposed for the 2016 ERP. The Company's rationale was that an abundance of small MW-sized proposals could exceed the data storage capabilities of the Strategist model used to develop and evaluate portfolios of

[34] See Commission Decision C14-0731 at paragraph 117.

proposals. Under such situations, the Strategist model begins to truncate portfolios (i.e., not examining all relevant portfolios) with the potential outcome of not finding the most cost-effective portfolios. A detailed description of the Company's proposal to evaluate bids down to 100 kW is discussed in Section 2.9 of Volume 2.

Company Ownership

As was done in the 2011 ERP, Public Service will offer utility-owned power supply proposals into the Phase II competitive acquisition process. Company self-build proposals will be sufficiently vetted such that the actual cost for constructing, operating and maintaining the proposed facilities will be within 20 percent of the cost contained in the proposal. Company proposals will be evaluated at their expected cost and performance.

These self-build proposals would also be used in the Phase II evaluation process to backfill portfolios that meet the RAP capacity need utilizing bids that do not extend to the end of the planning period. Section 2.9 of ERP Volume 2 discusses this evaluation methodology in detail.

It is expected that Company self-build proposal's would involve expanding the generation capacity at Public Services existing generation sites (i.e., "brownfield expansions"). Existing brownfield expansions include sites such as: Cherokee, Ft. Saint Vrain, Pawnee, and the Rocky Mountain Energy Center. The Company expects such brownfield expansion opportunities to offer cost-effective long-term options that will discipline pricing from IPPs and other utilities.

Owners of existing gas-fired generation facilities and developers of new gas and renewable generation are encouraged to offer the sale of existing generating assets and/or propose the construction of new generation for Company ownership. Capacity from the purchase of an existing asset must be useful to meet a portion of the RAP resource need not otherwise met from the asset. The Company has developed a Company Ownership RFP that will solicit offers to sell existing generation assets to the Company, accept build-own-transfer proposals for newly constructed facilities, and accept Company-owned proposals. This RFP is included in Volume 3 of this 2016 ERP.

Demand-Side Management Resources

The resource need to be acquired in Phase II over the RAP accounts for the impacts that the Company's existing and planned DSM and interruptible programs have on reducing the peak load on the system. The Commission has established separate processes outside the ERP process by which the appropriateness of the Company's proposed level of DSM achievements are reviewed and approved. As a result, and consistent with the Commission's 2011 ERP Phase I decision, the Company will not accept proposals offering additional DSM resources as part of the 2016 ERP Phase II competitive acquisition process.

120-Day Report

Within 120 days of receiving proposals, Public Service will file a report with the Commission describing its evaluation results including cost-effective portfolios that conform to the Commission's Phase I decision approving or modifying the 2016 ERP. Public Service will set forth its Preferred Portfolio and explain its reasons for the selection in the 120-Day Report.

1.7 RESERVE MARGIN AND CONTINGENCY PLAN

Planning Reserves for the 2016 ERP

For the 2016 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[35] over the RAP to determine the amount of additional power supply 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 through a collaborative study 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" ("LOLP") of 1-day in 10-years, a common industry standard for an acceptable level of system reliability.

A more detailed discussion of the Planning Reserve Margin is included in Section 2.6 of Volume 2. The LOLP study is provided for reference in Section 2.13 of Volume 2.

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, the Company's contingency plan focuses on events that could contribute to a capacity shortfall situation. Two key factors dictate whether a particular corrective action will provide a a viable solution for a particular contingency event. These factors are the magnitude of the potential resource shortfall, and the timing associated with the potential capacity shortfall – both the lead-time to the contingency and the duration of the event.

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

[35] 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 the effects of the Company's energy efficiency and firm interruptible load programs.

degree of flexibility in how we plan to address various contingencies. Section 2.6 of Volume 2 provides a more detailed discussion of the Contingency Plan and includes Table 2.6-1 Hierarchy of Contingency Plan Alternatives, which 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 versus the permanent loss of a planned resource, and the magnitude of the contingency.

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 2016 ERP.