BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

*** * * ***

IN THE MATTER OF THE	**)**
APPLICATION OF PUBLIC SERVICE	**)**
COMPANY OF COLORADO FOR	**) PROCEEDING NO. 16A-0396E**
APPROVAL OF ITS 2016 ELECTRIC	**)**
RESOURCE PLAN	**)**

DIRECT TESTIMONY OF JAMES F. HILL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

May 27, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF COLORADO

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IN THE MATTER OF THE	**)**	
APPLICATION OF PUBLIC SERVICE	**)**	
COMPANY OF COLORADO FOR	**)**	**PROCEEDING NO. 16A-0396E**
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SUMMARY OF THE DIRECT TESTIMONY OF JAMES F. HILL

Mr. James F. Hill is Director, Resource Planning of Xcel Energy Services Inc. In this position he is responsible for overseeing the Company's resource planning and competitive resource acquisition processes as well as the various technical analyses on the generation resource options that are available to Xcel Energy's four utility operating companies, including Public Service Company of Colorado ("Public Service" or the "Company") for meeting customer demand.

Mr. Hill supports the Company's Application by explaining the Company's rationale for the proposed Resource Acquisition Period ("RAP") and Planning Periods proposed for this 2016 Electric Resource Plan ("2016 ERP"), as well as discussing the assessment of resource needs, and the modeling analyses of alternative plans.

Mr. Hill describes the Company's proposal to use an eight (8)-year RAP that starts in May 2016 and runs through May 2024. The 8-year RAP will allow for solar facilities to take advantage of the Investment Tax Credit ("ITC") and is neutral regarding the Production Tax Credit ("PTC") given that it would allow consideration of wind facilities that qualify for all levels of credit (i.e., 100%, 80%, 60%, 40%, and 0%). The RAP is also long enough to allow sufficient time to attract proposals offering to construct new generation facilities during the RAP, allowing approximately 24, 36, 48, or 60 months to construct new generation facilities to meet a 2020, 2021, 2022, or 2023 resource need.

Mr. Hill states that the Strategist model that will be used in the evaluation of Phase II power supply proposals is dimensioned for years 2015 to 2054. Therefore, Public Service proposes a thirty-nine (39)-year Planning Period for the 2016 ERP.

Mr. Hill provides the Company's assessment of need for additional generation resources through the RAP, which currently shows: (1) a need in years 2022 and 2023 for additional generation capacity to maintain acceptable system reliability; (2) no need for additional renewable resources for the purpose of meeting the "minimum amounts" reflected in the percentage requirements of the Renewable Energy Standard ("RES"); (3) no need for additional flexible resources for purposes of integrating 600 MW of additional wind generation onto our system; and (4) a potential need for additional carbon reduction efforts to comply with the general CO2 emission reductions outlined in the EPA's Clean Power Plan ("CPP").

Mr. Hill describes how Public Service compared the peak electric demand forecast with the existing and planned generation resources (i.e., the load and resource balance) to forecast whether sufficient reserve margin would be maintained throughout each summer peak season during the RAP to meet the Company's proposed 16.3% reserve margin level. The current load and resource balance forecasts that there is no capacity need for years 2017-2021 and capacity needs of 284 MW in 2022 and 615 MW (cumulative) in 2023. The Company proposes that, prior to receipt of proposals in the 2016 ERP Phase II competitive acquisition process, the load and resource balance will be updated using the most current forecasts of peak demand and generation supply as well as any resource-related impacts of the Commission's decisions in various pending proceedings.

Mr. Hill sets forth the Company's evaluation of alternative plans to estimate the costs and benefits associated with meeting a portion of the RAP needs with increasing levels of renewable resources in accordance with Commission Rule 3604(k). The cost and benefits of a baseline plan and those of alternative plans with increasing levels of renewable resources were compared with one another over the 39-year Planning Period of 2016-2054. A total of four categories of generation technologies were included in the development of the alternative plans: (1) gas-fired combustion turbines; (2) gas-fired combined cycles; (3) utility scale wind; and (4) utility scale photovoltaic solar ("PV solar"). Mr. Hill provides the results of the analysis in Table JFH-2.

Although the Company does not present a preferred plan, Mr. Hill's take-away from the evaluation of alternative plans is that a combination of gas-fired peaking units and renewable resources that take advantage of the PTC and ITC are a lower cost option for meeting the RAP needs than an all-gas portfolio. Mr. Hill expects a similar outcome in the Phase II competitive acquisition process. Mr. Hill concludes that the recent extension of the PTC and ITC have created another opportunity to reduce customers future power supply costs through the addition of more PTC- and

ITC-eligible resources. Mr. Hill also finds that that each of the alternative plans is expected to have beneficial impacts to the RESA.

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DIRECT TESTIMONY OF JAMES F. HILL

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
BOT	Build Own Transfer
CACJA	Clean Air Clean Jobs Act
CC	Combined Cycle
CO_2	Carbon Dioxide
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CPUC	Colorado Public Utilities Commission
C.R.S.	Colorado Revised Statutes
DG	Distributed Generation
DR	Demand Reduction
DSM	Demand Side Management
EE	Energy Efficiency
EPA	Environmental Protection Agency
ERP	Electric Resource Plan
DSM	Demand Side Management
IPP	Independent Power Producer
ITC	Investment Tax Credit
kW	Kilowatt
kWh	Kilowatt-hour
LCI	Load Commutated Inverter

LOLP	Loss of Load Probability
MWh	Megawatt hour
PPA	Power Purchase Agreement
PTC	Production Tax Credit
Public Service or Company	Public Service Company of Colorado
PV	Photovoltaic
PVRR	Present Value Revenue Requirement
RAP	Resource Acquisition Period
RECs	Renewable Energy Credits
RE Plan	Renewable Energy Plan
RES	Renewable Energy Standard
RESA	Renewable Energy Standard Adjustment
Retail DG	Retail Distributed Generation
RFP	Request for Proposal
RP Rules	Resource Planning Rules
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2016 ELECTRIC RESOURCE PLAN

) PROCEEDING NO. 16A-0396E

DIRECT TESTIMONY OF JAMES F. HILL

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James F. Hill. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Xcel Energy Services Inc. ("XES") as Director, Resource Planning. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or "Company") and the other three utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Director, Resource Planning, I am responsible for overseeing the Company's resource planning and competitive resource acquisition processes, as well as the various technical analyses on the generation resource options that are available to Xcel Energy's operating companies for meeting customer demand. A description of my qualifications, duties, and responsibilities is included at the end of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to discuss the:

- Resource Acquisition Period ("RAP") and Planning Periods proposed for this 2016 Electric Resource Plan ("2016 ERP");
- assessment of resource needs; and
- modeling analyses of alternative plans.

II. SELECTION OF RAP AND PLANNING PERIODS

Q. WHAT IS THE SIGNIFICANCE OF THE RESOURCE ACQUISITION PERIOD?

A. The Commission's resource planning rules allow jurisdictional utilities to select a Resource Acquisition Period ("RAP") between six and ten years from the date the plan is filed. The RAP is the period of time over which the utility acquires specific generation resources to meet projected resource needs.

Q. WHAT RESOURCE ACQUISITION PERIOD IS THE COMPANY PROPOSING FOR THIS 2016 ERP?

A. For this 2016 ERP, the Company is proposing an 8-year RAP that starts in May 2016 and runs through May 2024. The practical application of this 8-year RAP is that it will address the resource needs through the summer peak season of 2023.

Q. WHAT RAP DID THE COMPANY PROPOSE IN THE 2011 ERP?

A. In the 2011 ERP the Company proposed a 7-year RAP that ran from October 2011 to October 2018.

Q. HOW DID THE COMPANY ASSESS THE APPROPRIATE RESOURCE ACQUISITION PERIOD FOR THIS 2016 ERP?

A. Section 1.3 of ERP Volume 1 includes a discussion of the Company's assessment of the appropriate RAP. In summary the Company considered: (1) the relationship between the RAP and recent extensions of the federal

Production Tax Credit ("PTC") and Investment Tax Credit ("ITC"); (2) the time between when Phase II proposals would be due and when the resource needs occur, which influences how far into the future suppliers need to offer firm pricing; (3) the time between when Phase II is completed and when the resource needs occur, which influences the amount of time available to construct new generation resources; and (4) how the RAP in this ERP might impact the next ERP.

Q. HOW DOES AN 8-YEAR RAP ALIGN WITH THE ITC AND PTC?

A. The PTC and ITC extensions are discussed in the Direct Testimony of Company witness Ms. Alice Jackson. The ITC allows solar facilities to begin construction as late as December 31, 2019 and qualify for the 30% ITC. Such facilities would have several years to complete construction and begin commercial operation in order to help meet a portion of the summer 2022 or 2023 need.[1] The 8-year RAP is neutral with regard to the PTC given that it would allow consideration of wind facilities that qualify for all levels of credit (i.e., 100%, 80%, 60%, 40% and 0%).

Q. HOW DOES AN 8-YEAR RAP TAKE INTO CONSIDERATION THE TIME BETWEEN WHEN PHASE II IS COMPLETED AND WHEN THE RESOURCE NEEDS OCCUR?

A. The Company wants the RAP to be long enough to allow sufficient time to

[1] Assuming they begin commercial operation in May 2022 and May 2023.

attract proposals offering to construct new generation facilities (referred to herein as "new construction"). Establishing a RAP that allows proposals offering new construction to compete with proposals from existing generation facilities provides an added level of discipline to the process. If this 2016 ERP proceeds along a schedule similar to the 2011 ERP, the Phase II acquisition process should be completed and a Commission decision rendered in the May 2018 timeframe. This would allow approximately 24, 36, 48, or 60 months to construct new generation facilities to meet a 2020, 2021, 2022, or 2023 resource needs. This should be more than adequate time to develop a variety of generation technologies, including gas-fired combustion turbine or combined cycle facilities, as well as wind and solar PV.

Q. WHAT PLANNING PERIOD IS THE COMPANY RECOMMENDING AND WHY?

A. The ERP Rules require that the planning period be between 20 and 40 years. The Strategist model that will be used in the evaluation of Phase II power supply proposals is dimensioned for years 2015 to 2054. Therefore, Public Service proposes a 39-year Planning Period for the 2016 ERP.

III. ASSESSMENT OF RESOURCE NEED

Q. PLEASE SUMMARIZE THE COMPANY'S ASSESSMENT OF THE NEED FOR ADDITIONAL GENERATION RESOURCES.

A. The assessment of need is focused on four areas:

1. System reliability;
2. Compliance with the Renewable Energy Standard ("RES");
3. Flexible resources for integrating intermittent resources; and
4. EPA's Clean Power Plan ("CPP").

The results of these assessments identified: (1) a need in years 2022 and 2023 for additional generation capacity to maintain acceptable system reliability; (2) no need for additional renewable resources for the purpose of meeting the "minimum amounts" reflected in the percentage requirements of the RES;[2] (3) no need for additional flexible resources for purposes of integrating 600 MW of additional wind generation onto our system, and (4) a potential need for additional carbon reduction efforts to comply with the general CO2 emission reductions outlined in the CPP through the RAP.

[2] No additional wholesale DG or non-DG resources are needed to comply with the RES through beyond 2030. The need for additional retail-DG resources are determined in the Company's Renewable Energy Plan filings.

Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL GENERATION RESOURCES ARE NEEDED FOR SYSTEM RELIABILITY PURPOSES?

A. By comparing the peak electric demand forecast discussed in the testimony of Company witness Ms. Jannell Marks with the existing and planned generation resources (commonly referred to as a load and resource balance), we are able to forecast whether sufficient planning reserve margin would be maintained throughout each summer peak season during the RAP. Planning reserve margin is the amount of generation capability in excess of peak firm obligation load that a utility carries on its system in order to meet customer demand under system uncertainties. The Company proposes utilizing a 16.3% planning reserve margin for this 2016 ERP, which amounts to having approximately 1,100 MW more generation capability than firm load obligation.

Q. WHAT PLANNING RESERVE MARGIN DID THE COMMISSION APPROVE FOR USE IN THE 2011 ERP?

A. The Commission approved use of a 16.3% reserve margin for purposes of determining the resource need in the Company's 2011 ERP and associated 2013 All-Source Solicitation. We are thus seeking approval of the same planning reserve margin in this 2016 ERP as in the 2011 ERP.

Q. WHAT IS THE BASIS FOR A 16.3 % PLANNING RESERVE MARGIN?

A. The 16.3% planning reserve margin was calculated using a stochastic analysis of the Company's system to determine the level of planning reserve margin necessary to reliably maintain service to load.

Q. WHAT DID THE STOCHASTIC ANALYSIS CONCLUDE?

A. The analysis utilized the metric of Loss of Load Probability ("LOLP") equal to 1 day in 10 years as being representative of an acceptable level of reliability. This 1 day in 10 year level of LOLP is equivalent to failing to serve the full energy requirements of the system for 2.4 hours each year and is a common measure of acceptable reliability in the industry. The study concluded that a 16.3% planning reserve margin applied to the 50th percentile demand forecast would meet this 1 day in 10 year LOLP level. The study report is included in ERP Volume 2.

Q. HOW ARE THE EFFECTS OF THE COMPANY'S DEMAND SIDE MANAGEMENT AND DEMAND RESPONSE PROGRAMS ACCOUNTED FOR IN THIS LOAD AND RESOURCE BALANCE?

A. As has been the case in all prior ERPs, the forecast of summer peak load is reduced by the combined effects of the Company's Demand Side Management ("DSM") Energy Efficiency ("EE") programs and demand response programs (e.g., interruptible load and savers switch programs) based on approved Commission goals. The resulting load is referred to as firm obligation load. The 16.3% planning reserve margin is applied to the forecast of firm obligation load for each year of the RAP.

Q. WHAT IS THE COMPANY'S ASSESSED NEED FOR ADDITIONAL GENERATION CAPACITY OVER THE RAP TO MAINTAIN ACCEPTABLE SYSTEM RELIABILITY?

A. The current load and resource balance forecasts that there is no capacity need for years 2017-2021 and capacity needs of 284 MW in 2022 and 615 MW[3] in 2023. A summary load and resource balance is included in Section 1.4 of ERP Volume 1, and a more detailed version is included in Section 2.12 of ERP Volume 2.

Q. DOES THE COMPANY INTEND TO UPDATE THIS LOAD AND RESOURCE BALANCE PRIOR TO THE PHASE II ACQUISITION PROCESS?

A. Yes. Public Service proposes that, prior to receipt of proposals in the 2016 ERP Phase II competitive acquisition process, the load and resource balance will be updated using the most current forecasts of peak demand and generation supply as well as any resource-related impacts of the Commission's decisions in various pending proceedings (e.g., Solar*Connect, 2017 RE Plan, Rule 3660(h) Rush Creek Wind Project CPCN). The RAP capacity needs identified in this updated load and resource balance will

[3] The 615 MW need is cumulative through 2023 and includes the 284 MW need of 2022.

establish the level of additional generation resources to be acquired through the Phase II competitive acquisition process. By updating the load and resource balance in this manner, the Company will better ensure that we acquire a sufficient amount of generation resources to reliably serve the peak demands during the RAP.

Q. HAS THE COMPANY USED A SIMILAR APPROACH IN PRIOR ERPs?

A. Yes. This approach to update the load and resource balance prior to the Phase II competitive acquisition process is consistent with the approach taken in both the 2007 ERP and 2011 ERP.

Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL RENEWABLE RESOURCES ARE NEEDED TO COMPLY WITH THE "MINIMUM AMOUNTS" REFLECTED IN THE PERCENTAGE REQUIREMENTS OF THE RES?

A. We did so by comparing the forecast of wholesale DG and non-DG RECs over time with the minimum percentage requirements in the RES statute and RES Rules. This comparison shows that the existing and planned Wholesale DG and non-DG renewable resources will generate enough RECs to comply with the minimum amounts in the RES beyond 2030. Details about the Company's REC projections to meet the Retail DG requirement are included in the 2017 RE Plan that was filed with the Commission on February 29, 2016, in Proceeding No. 16A-0139E.

Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL FLEXIBLE RESOURCES ARE NEEDED TO HELP INTEGRATE WIND AND SOLAR ONTO THE COMPANY'S ELECTRIC SYSTEM?

A. Company witness Mr. Kent Scholl discusses this assessment in his Direct Testimony. Mr. Scholl concludes that the Company has sufficient Flex Reserve to accommodate adding the 600 MW Rush Creek Wind Project to the existing system. The Company is in the process of examining the flexibility requirements for additional wind (i.e., more than the amount of wind analyzed in the Flex Reserve Study included with the Company's filing as Attachment JTW-2 in Proceeding No. 16A-0117E).

Q. WILL THE COMPANY ACCEPT PROPOSALS FOR MORE WIND AND SOLAR RESOURCES IN THE PHASE II ACQUISITION PROCESS?

A. Yes. We encourage power supply providers to propose new wind and solar generating facilities in the Phase II competitive acquisition process.

Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL CARBON REDUCTION EFFORTS MAY BE NEEDED ON ITS SYSTEM IN ORDER TO MEET THE CARBON REDUCTIONS OF THE CPP?

A. Although the Clean Power Plan has been stayed, the Company believes that there will be some form of future carbon regulation. As a result, through the evaluation of alternative plans that meet the RAP capacity needs with increasing levels of renewable resources, we estimated the carbon emissions from the Company's affected sources (i.e., sources subject to the emission reduction requirements in the Clean Power Plan) and considered the interaction of these emissions with potential state CPP compliance requirements. I discuss this evaluation later in my testimony.

IV. BASELINE CASE AND ALTERNATIVE PLAN OVERVIEW

Q. PLEASE DESCRIBE THE BASELINE CASE AND VARIOUS ALTERNATIVE PLANS THAT THE COMPANY EVALUATED.

A. The alternative plans provide the framework for estimating the costs and benefits (measured in PVRR[4]) associated with meeting the RAP capacity needs with increasing levels of renewable resources[5] in accordance with Commission Rule 3604(k). One alternative plan (referred to as a "baseline case") was developed to include: (1) all existing generation resources; (2) all completed and planned actions under the Clean Air Clean Jobs Act ("CACJA"); and (3) the renewable resources that are currently operating or under construction on the Public Service power supply system as of the time of this ERP filing.[6] The primary purpose of the baseline case is to serve as a cost foundation against which the costs and benefits of the alternative plans are compared. All four alternative plans meet the same RAP capacity needs. The cost of each alternative plan was estimated over the 39-year Planning Period of 2016-2054. All four plans include the same increasing level of DSM established by the Commission in Decision No. C14-0731 in Proceeding No.

[4] For this 2016 ERP, Present Value of Revenue Requirements ("PVRR") means the year 2016 worth of the total expected future revenue requirements associated with a particular resource portfolio, expressed in year 2016 dollars as discounted by the Company's current after tax weighted cost of capital of 6.78%.

[5] Public Service has chosen not to model any potential Section 123 technologies in its Phase I alternative plan analyses.

[6] The baseline case includes the 450 MW of wind and 170 MW of utility scale solar selected from the 2011 ERP Phase 2 acquisition process.

13A-0686EG for the entire 39-year planning period. Section 1.5 of ERP Volume 1 contains a detailed discussion of the alternative plan analysis.

Q. HOW WERE COST ESTIMATES FOR EACH ALTERNATIVE PLAN DEVELOPED?

A. The cost estimates were developed within the Strategist computer model using the same modeling methodology used by the Company in the 2011 ERP. That methodology consists of: (1) developing cost and performance estimates for a variety of generation technologies that are expected to be available to Public Service to meet the RAP capacity needs; and (2) using Strategist to construct different combinations of those technologies that meet the RAP capacity needs (i.e., portfolios). I discuss the various generation technologies included in these alternative plans later in my testimony.

Q. HOW WAS THE ANALYSIS OF THE ALTERNATIVE PLANS STRUCTURED?

A. Public Service structured the analysis of alternative plans to provide insight into the costs and benefits of adding renewable resources in two different time frames: (1) additions made during the 8-year RAP (2016-2023); and (2) additions made during the time beyond the RAP (2024-2054). This segmentation was done to separate cost and benefit information associated with increased renewables in the timeframe under consideration in this 2016 ERP (i.e., the 8-year RAP) from those that will be considered and addressed in future ERPs (i.e., additions beyond the RAP). Figure JFH-1 illustrates how the analysis was structured to examine renewable additions in these two timeframes. Discussions and conclusions later in my testimony regarding the analysis of alternative plans will focus on the renewable additions made during the 8-year RAP. That analysis is depicted in the top half of Figure JFH-1. In addition, more detail about the post-RAP renewable additions analysis is provided in Volume 1 of the ERP in Table 1.5-10 and in supporting discussion.

Figure JFH-1 - Alternative Plan Analysis Framework

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.

Q. WHAT LEVEL OF DSM ENERGY EFFICIENCY WAS REFLECTED IN THESE ALTERNATIVE PLANS?

A. The level of DSM EE included in the alternative plan analysis is consistent with the level of DSM resources that the Commission established in Proceeding No. 13A-0686EG.

Q. WHAT LEVEL OF CUSTOMER CHOICE PROGRAMS WAS REFLECTED IN THESE ALTERNATIVE PLANS?

A. The level of customer choice[7] resources for years 2017-2019 was represented in the alternative plan modeling consistent with those proposed in the Company's Solar*Connect filing (i.e., 50 MW of solar PV in 2018) and the Company's 2017 RE Plan filing (i.e., 87 MW, 98 MW, and 106 MW DC for 2017, 2018 and 2019, respectively). Growth in customer choice programs beyond 2019 was assumed at approximately 105 MW DC each year.

Q. DOES THE COMPANY INTEND TO ACQUIRE ANY DSM EE OR RESOURCES TO SUPPLY CUSTOMER CHOICE PROGRAMS IN PHASE II OF THIS 2016 ERP?

A. No. As a practical matter, the amount of DSM EE and customer choice that Public Service will acquire over time are proposed and adjudicated in stand-alone proceedings separate from the ERP. For example, at the time of this ERP filing, the Company has two proceedings pending before the Commission that propose additional levels of customer choice, the Solar*Connect proceeding and the 2017 RE Plan proceeding.

[7] Customer choice refers to participation in the Company's Small, Medium, and Large Solar*Rewards and Solar*Rewards Community solar gardens programs.

Q. IF THE COMPANY DOES NOT INTEND TO ACQUIRE DSM EE OR RESOURCES FOR CUSTOMER CHOICE PROGRAMS THROUGH THE PHASE II PROCESS OF THIS 2016 ERP, THEN WHY IS IT INCLUDED IN THE ANALYSIS OF ALTERNATIVE PLANS?

A. DSM EE and customer choice programs are included because, in assessing the need for additional generation resources and the potential customer cost/savings impacts of those additions, it is important to account for all sources of future DSM achievements as well as all sources of future generation supply that are likely to be added through proceedings other than the ERP. In this regard, the ERP process represents an integrated view of how these various activities function together to serve the electric supply needs of our customers. For example, when assessing in an ERP whether additional generation capacity is needed to maintain an acceptable level of reliability, it is important to include all sources of generation supply (both existing and planned) as well as all sources of DSM (EE, DR, and Interruptible programs) within that assessment. In doing so, we better ensure that any additional generation capacity acquired through the ERP is in fact needed for purposes of maintaining acceptable overall system reliability.

V. RESOURCE TECHNOLOGIES CONSIDERED IN THE ANALYSIS OF ALTERNATIVE PLANS

Q. PLEASE SUMMARIZE THE VARIOUS GENERATION TECHNOLOGIES INCLUDED IN THE DEVELOPMENT OF THE ALTERNATIVE PLANS.

A. The Company considered a total of four different categories of generation technologies: (1) gas-fired combustion turbines; (2) gas-fired combined cycles; (3) utility scale wind; and (4) utility scale photovoltaic solar ("PV solar"). Gas-fired combustion turbine and combined cycle cost and performance estimates were developed by employees within the Company's engineering and construction department. These estimates were developed using a similar process as that used in the 2011 ERP for gas-fired technologies and include all major cost and performance characteristics for an installation within Colorado. Cost and performance estimates for PV solar technologies were developed within the Company's resource planning department based on information received from past Public Service requests for proposal ("RFPs"). PV solar cost estimates were developed for four levels of ITC, 30%, 26%, 22% and 10%. The cost and performance estimates for gas-fired and PV solar resource technologies are referred to as "generic resources" because they do not reflect a specific site location. For wind generation qualifying for the 100% PTC benefit, cost and performance information was based on the 600 MW Rush Creek Wind Project for which the Company has filed a CPCN application with the Commission. Generic cost and performance estimates were used to represent wind generation qualifying for lower levels of the PTC.

Q. DID THE COMPANY INCLUDE ANY POTENTIAL SECTION 123 GENERATION TECHNOLOGIES IN THE DEVELOPMENT OF THE ALTERNATIVE PLANS?

A. No. In its 2011 ERP Phase I Decision, the Commission stated a preference to review and decide on developer claims for Section 123 status in the Phase II proceeding.[8] As a result, Public Service has chosen not to model any potential Section 123 technologies in its Phase I alternative plan analyses. However, prospective bidders may propose potential Section 123 resources in the Phase II solicitation, as discussed in more detail in Section 2.9 of Volume 2.

Q. DID THE COMPANY INCLUDE ANY POTENTIAL DSM TECHNOLOGIES IN THE DEVELOPMENT OF THE ALTERNATIVE PLANS?

A. No. In its 2011 ERP Phase I Decision (Decision No. C13-0094 at Paragraph 108) addressing applications for rehearing, reargument, or reconsideration, the Commission agreed with the Company that it was more practical to address the acquisition of DSM resources (i.e., EE and demand response) in a process separate from the ERP. As a result, Public Service did not model

[8] See Section 1.5 of ERP Volume 1 for additional details.

any potential additional demand-side resources/programs in its Phase I alternative plan analysis.

Q. WHAT LEVEL OF ADDITIONAL RENEWABLES WERE INCLUDED IN THE VARIOUS ALTERNATIVE PLANS?

A. Table JFH-1 shows the levels of renewable resources added during the RAP in each of the alternative plans. Note that the baseline case and alternative plan 1 are synonymous with one another.

Table JFH-1 – RAP Renewable Resource Additions

RAP Renewable Resource Additions	Alternative Plan			
	1	2	3	4
Baseline Case/Alterative Plan 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**

VI. ALTERNATIVE PLAN ANALYSIS SUMMARY

Q. HOW DID THE COST OF ALTERNATIVE PLANS THAT FOCUSED ON INCREASED RENEWABLES IN THE 8-YEAR RAP COMPARE WITH ONE ANOTHER?

A. Under the base assumptions for electric sales and natural gas prices, the addition of the Company's proposed 600 MW Rush Creek Wind facility (alternative plan 2) showed customer savings of $440 million.[9] The $440 million savings to customers is derived by taking the difference between the PVRR savings of alternative plan 1 and alternative plan 2. The combined addition of 600 MW of Rush Creek Wind facility and 400 MW of generic wind (alternative plan 3) showed savings of $590 million compared to plan 1, while the combined addition of the 600 MW Rush Creek Wind facility and 400 MW of utility scale solar (alternative plan 4) showed $570 million in savings compared to plan 1. Table JFH- 2 summarizes these results.

Table JFH-2 – Alternative Plan Analysis Summary

RAP Renewable Resource Additions	Alternative Plan			
	1	2	3	4
Baseline Case/Alterative 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**
PVRR Delta From Baseline ($M) (5)	**$0**	**($440)**	**($590)**	**($570)**

[9] All PVRR values throughout this document are rounded to the nearest $10 million.

Q. WHAT DO YOU THINK IS THE GENERAL TAKE-AWAY FROM THE EVALUATION OF ALTERNATIVE PLANS?

A. The evaluation results indicate that under base assumptions the combination of (1) gas-fired peaking units (to provide capacity) and (2) renewable resources (to provide capacity and energy) that take advantage of the PTC and ITC are a materially lower cost option for meeting the RAP needs than an all-gas portfolio. Public Service expects a similar outcome in the Phase II competitive acquisition process.

Q. WHAT LEVEL OF PVRR SAVINGS DO YOU CONSIDER TO BE MATERIAL?

A. The question of what constitutes a material PVRR cost difference between different plans or portfolios often arises in a resource planning proceeding. Parties tend to compare the planning period PVRR cost differences or deltas between different plans or portfolios with the planning period PVRR cost of the entire system. This type of comparison often depicts the cost deltas between plans as a very minor percentage of the total Planning Period costs for the entire power supply system. Parties have used this type of comparison to argue in favor of higher or lower cost plans that contain specific generation technologies they support.

I believe the question of what constitutes a material cost difference among plans is more appropriately framed by considering the MW of power supply needs that are under consideration, or "in-play," in an ERP proceeding, and then comparing cost deltas between plans against an estimate of the costs that are in-play.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THIS COMPARISON WOULD WORK?

A. Yes. In this 2016 ERP, approximately 600 MW of generation capacity is needed to meet the RAP capacity needs (i.e., 600 MW are in-play) based on the current projection of the resource need. Using an estimate of the all-in cost of energy for the generic combined cycle cost (about $75/MWh), one can estimate that the cost of 600 MW of generation over the planning period would be in the general range of $1.7 billion PVRR. With this general range, one can see that each $17 million of PVRR delta between plans represents approximately 1% of the total power supply costs that are in-play in this ERP. Applying this simple rule of thumb to the $440 million PVRR savings of the 600 MW of wind in alternative plan 2 represents a savings equal to about 26% ($440 million / $17 million = 26) of the total power supply costs under consideration in this ERP. I believe this simple rule of thumb provides a more useful view of what constitutes a material difference between plans in this ERP.

Q. HOW DID THE COST OF THE BASELINE CASE AND ALTERNATIVE PLANS COMPARE WITH ONE ANOTHER UNDER DIFFERENT GAS PRICE ASSUMPTIONS?

A. Under the low gas price sensitivity, the 600 MW of 100% PTC wind (alternative plan 2) continues to provide savings of over $200 million. The 80% PTC wind and 30% ITC solar credits reflected in alternative plans 3 and 4, however, are essentially economically neutral in that they provide no material added costs or savings to the system under low gas prices. In other words, in the low gas price sensitivity there are no material incremental savings attributable to the 80% PTC wind and 30% ITC solar beyond the savings provided by the 600 MW of 100% PTC wind. Finally, and not surprisingly, under high gas prices, both levels of PTC wind show considerable savings as does the 30% level of ITC solar. Table JFH-3 summarizes the results of the gas price sensitivity analysis.

Table JFH-3 – Alternative Plan Gas Price Sensitivity Summary

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**
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)

Q. WHAT IS YOUR GENERAL TAKE-AWAY FROM THE GAS PRICE SENSITIVITY ANALYSIS OF ALTERNATIVE PLANS?

A. The evaluation results reinforce the conclusion that a combination of gas-fired peaking units and renewable resources that take advantage of the PTC and ITC are a lower cost option for meeting the RAP needs than an all-gas portfolio. Even under a low gas price future, the addition of the wind and solar resources in alternative plans 2, 3, and 4 continue to show savings of 11%-12% (assuming each $17 million is about 1%) over the all-gas portfolio represented in alternative plan 1. Following on my earlier discussion, I consider these savings to be material.

Q. DO YOU BELIEVE THE ANALYSIS OF ALTERNATIVE PLANS PROVIDES INSIGHT INTO THE POTENTIAL NEED FOR PUBLIC SERVICE TO PURSUE ADDITIONAL CARBON REDUCTION EFFORTS IN THIS ERP TO MEET THE CARBON REDUCTIONS OF CPP?

A. Yes, in a very general sense. However, at this time we do not know the level of future CO_2 reductions we will be required to achieve, what does or does not qualify for emission reduction purposes, or what the best overall combination of actions (e.g., renewable additions, gas-shifting, early coal retirements) and timing of those actions will be that would allow us to achieve any required emission reductions in a least-cost manner.

Q. RECOGNIZING THESE LIMITATIONS, WHAT INFORMATION CAN THE COMMISSION GLEAN FROM THE ALTERNATIVE PLAN ANALYSIS TO HELP INFORM ACTIONS THAT CAN BE TAKEN IN THIS ERP TO BETTER POSITION PUBLIC SERVICE TO POTENTIALLY COMPLY WITH THE CPP?

A. I believe the alternative plan analysis provides an indication that pursuit of additional low cost renewable wind and solar generation that qualify for the full PTC and ITC represents a "no regrets" opportunity for customers to realize substantial cost savings while at the same time further enhancing the Company's position to address future public policy regulations regarding carbon. These "no regrets" opportunities are discussed further in the testimony of Company witness Ms. Alice Jackson.

Q. DID THE COMPANY ALSO ESTIMATE THE RESA IMPACTS ASSOCIATED WITH EACH OF THE ALTERNATIVE PLANS?

A. Yes. We estimated the RESA impacts using the methodology described in the Company's 2017 RE Plan (Proceeding No. 16A-0139E). In general, this approach involves RES/No-RES modeling. We create a No-RES Plan, which is intended to represent the system and associated costs that would have otherwise been incurred had it not been for the addition of renewable energy resources to the system. The annual costs for each of the alternative plans, with the alternative plan's relevant level of renewable resource additions, are then compared to those of the No-RES Plan. The result isolates the incremental costs or savings of the new renewable resources. The incremental costs or savings are then allocated to the RESA.

Q. WHAT WERE THE RESULTS OF THAT RESA ANALYSIS?

A. The analysis showed that each of the alternative plans is expected to have beneficial impacts to the RESA. Additional details on the analysis results are discussed in Section 1.5 of ERP Volume 1.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE ANALYSES OF THESE ALTERNATIVE PLANS?

A. The basic conclusions that I draw from these analyses are:

1. The evaluation of alternative plans indicates that a combination of gas-fired peaking units and renewable resources that take advantage of the PTC and ITC are a lower cost option for meeting the RAP needs than an all-gas portfolio.
2. The recent extension of the PTC has created another opportunity to reduce future customer power supply costs through the addition of more PTC-eligible wind resources. The ability of the Company's proposed 600 MW of wind (the Rush Creek Wind Project) to qualify for 100% of the PTC is key to producing the $440 million in estimated savings for customers. If the project were to be delayed and qualify for 80% of the PTC, that would cost customers over $100 million in lost savings. The economic value of the full PTC is such that even under low gas price assumptions, the 600 MW wind addition showed considerable customer

cost savings of approximately $200 million PVRR. Under the high gas price sensitivity, the 600 MW of wind showed over $700 million of customer savings.

3. Similarly, but to a lesser degree, the recent extension of the ITC has also created opportunities to reduce customer power supply costs through the addition of ITC-eligible utility scale PV solar resources. The economic value of the 30% ITC versus the lower 26% and 22% levels is less pronounced in the modeling of alternative plans.[10] As a result, there is less of a sense of urgency associated with acquiring additional solar.

Q. IS THE COMPANY ASKING THE COMMISSION TO ENDORSE ONE OF THE FOUR ALTERNATIVE PLANS IN THIS PHASE I PROCESS?

A. No. As addressed by Company witness Ms. Alice Jackson in her Direct Testimony, the Company does not present a preferred plan, but instead provides a path and process forward (through 2023) that recognizes and encourages the transition from our current generation fleet to one that includes more distributed energy resources, greater customer participation in their energy choices, and increasing levels of renewable energy resources.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[10] See Figure 1.5-5 of ERP Volume 1.

James F. Hill

Statement of Qualifications

As the Director of the Resource Planning and Bidding Group, I am responsible for overseeing the Company resource planning and competitive resource acquisition processes as well as the various technical analyses on the generation resource options that are available to Xcel Energy's operating companies for meeting future customer demand. I graduated from Colorado State University with a Bachelor of Science degree in Natural Resource Management and from the University of Colorado with a Bachelor of Science degree in Mechanical Engineering. I have been employed by Public Service Company of Colorado, New Century Services, Inc., and now Xcel Energy Services Inc. for over 30 years. I have testified before the Colorado Public Utilities Commission regarding electric resource planning issues in numerous dockets.