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	**)**	**DOCKET NO. _____E**
FOR APPROVAL OF ITS 2011 ELECTRIC	**)**	
RESOURCE PLAN	**)**	

DIRECT TESTIMONY OF JAMES F. HILL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 31, 2011

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OF THE STATE OF COLORADO

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**BEFORE THE PUBLIC UTILITIES COMMISSION
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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2011 ELECTRIC RESOURCE PLAN	**))))**	**DOCKET NO. _____E**

<u>DIRECT TESTIMONY OF JAMES F. HILL</u>

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James F. Hill. 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., the service company subsidiary of Xcel Energy Inc., the registered public utility holding company parent of Public Service Company of Colorado ("Public Service", or "Company"). My title is Director, Resource Planning and Acquisition. My qualifications are included as Attachment A.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. To discuss the Resource Acquisition Period ("RAP") and Planning Periods proposed for this 2011 Electric Resource Plan ("2011 ERP"), the assessment of resource needs, the various economic analyses of alternative plans presented in ERP Volume 1, the proposed assessment of alternatives to burning gas in Arapahoe 4 and Cherokee 4, and the proposed Phase 2 competitive solicitation process.

II. <u>SELECTION OF RAP AND PLANNING PERIODS</u>

Q. HOW DID THE COMPANY ASSESS THE APPROPRIATE RESOURCE ACQUISITION PERIOD AND PLANNING 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 needed to meet projected resource needs. For this 2011 ERP, the Company selected a seven-year RAP that starts in October 2011 and runs through October 2018. The current assessment of need, estimates that the first year that additional generation capacity would be needed is 2017, with additional capacity needed in 2018. If this 2011 ERP proceeds along a schedule similar to the 2007 ERP, the Phase 2 acquisition process should be completed by the fall of 2013. This would allow approximately fifty seven months for design, permitting, and construction of any winning proposals offering the construction of new generation facilities for an in-service date of May 1, 2018, approximately two months in advance of when that year's July summer peak load is likely to occur. This should be more than adequate time to develop a variety of generation technologies, such as gas-fired combustion turbine or combined cycle facilities as well as wind, solar PV, and solar thermal facilities to name a few. Looking forward to the 2015 ERP, I would expect that the first year in which additional generation capacity would be needed would be 2019, approximately thirty three months beyond the fall of 2016 when I would expect that 2015 ERP Phase 1 process to be completed and twenty one months beyond when I would expect the Phase 2 process to be completed. These timeframes should again be sufficient to construct a variety of generation technologies that could provide the capacity needed to ensure system reliability. If the Company sees a change in load growth forecasts for that 2019 time period, we could file the 2015 ERP early to ensure sufficient time for generation construction.

III. ASSESSMENT OF RESOURCE NEED

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

A. The assessment focused on three areas: system reliability, compliance with the Renewable Energy Standard ("RES"), and flexible resources needed for integrating intermittent generating resources. The results of these assessments identified: 1) a need in 2017-2018 for additional generation capacity for system reliability purposes; 2) no need for additional renewable resources to meet the RES;[1] and 3) no need for additional flexible resources for purposes of integrating intermittent generation into our system.

[1] No additional wholesale DG or non-DG resources are needed to comply with the RES through approximately 2028. The need for additional retail-DG resources are determined in the Company's RES Compliance plan filings and acquired through Solar*Rewards programs administered outside the ERP process.

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

A. By comparing the peak electric demand forecast with the existing and planned generation resources (commonly referred to as load and resource balance), we were able to determine 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 should carry in order to meet customer demands under expected system uncertainties. The Company proposes utilizing a 16.3% planning reserve margin for this 2011 ERP, which amounts to having approximately 1,000 MW more generation capability than firm load obligation.

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

A. In 2008 Public Service retained Ventyx to perform a stochastic analysis of the Company's system to determine the level of planning reserve margin necessary to reliably maintain service to load. The analysis focused on the year 2013 which is within the RAP for the 2011 ERP. The year 2013 was selected in order to capture the effect of the 787 MW Comanche 3 facility on the system. Comanche 3 now represents the largest single contingency for Public Service as well as the rest of the Rocky Mountain Reserve Group ("RMRG") of which Public Service is a member. The largest single contingency on any electric power system influences the level of planning reserve margin that a system carries.

Q. WHAT IS THE ROCKY MOUNTAIN RESERVE GROUP?

A. The Rocky Mountain Reserve Group is a group of utilities who have agreed to pool their resources to meet operating reserve requirements as a group in a more efficient manner than the individual utilities could meet on their own.

Q. WHAT DID THE VENTYX ANALYSIS CONCLUDE?

A. The Ventyx 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. 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 Ventyx study report (see Section 2.10 of the 2011 ERP, Volume 2 Technical Appendix) was filed with the Commission in December 2008. The Commission approved use of the study results for purposes of determining the resource need in the Company's 2009 All-Source Solicitation.

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. The forecast of summer peak load is reduced by the combined effects of the Company's DSM programs and demand response programs (interruptible load and savers switch programs). 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 DID THE LOAD AND RESOURCE BALANCE FOR THE RAP SHOW?

A. That additional generation capacity of approximately 60 MW in 2017 and 290 MW in 2018 was needed in order to achieve the desired 16.3% planning reserve margin. The load and resource balance is included in Section 2.11 of Volume 2 Technical Appendix.

Q. DOES THE COMPANY INTEND TO UPDATE THIS LOAD AND RESOURCE BALANCE?

A. Yes. Public Service proposes that prior to receipt of bids in the Phase 2 competitive solicitation process, the load and resource balance will be updated using the then most current forecasts of peak demand and generation supply. The RAP capacity needs identified in this updated load and resource balance would establish the level of additional generation resources to be acquired through the Phase 2 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. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL RENEWABLE RESOURCES ARE NEEDED TO COMPLY WITH THE RENEWABLE ENERGY STANDARD?

A. By comparing the forecast of wholesale DG and non-DG RECs over time with the requirements of the Renewable Energy Standard. This comparison shows that the existing and planned wholesale DG and non-DG renewable resources will generate enough RECs to comply with the RES through approximately 2028. Figures 1.4-2 and 1.4-3 in ERP Volume 1 summarize the results of these analyses. Details about the Company's REC projections are included in the 2014 RES Compliance Plan that was filed with the Commission on October 31, 2011.

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

A. Company witness Keith Parks discusses this assessment in his Direct Testimony.

IV. BASELINE CASE AND ALTERNATIVE PLANS

Q. PLEASE DESCRIBE THE LEAST-COST BASELINE CASE AND ALTERNATIVE PLANS.

A. These plans provide cost estimates of nine different plans for meeting the RAP capacity needs with increasing levels of renewable, demand side management, and Section 123 resources. The Commission rules require such plans be included in a utility's ERP. The "least-cost baseline case" is the plan that meets the RAP needs at the lowest cost as measured by net present value of revenue requirements ("PVRR"). The other eight plans are referred to as "Alternative Plans" which meet the same RAP need but with increasing levels of renewable and Section 123 resources. Each plan's cost is estimated over the forty year Planning Period ending in 2050. All nine plans include the same increasing level of DSM established in CPUC Docket No. 10A-554EG in compliance with the requirements of C.R.S. §40-3.2-104.

Q. HOW WERE THE LEAST-COST BASELINE CASE AND ALTERNATIVE PLAN COST ESTIMATES DEVELOPED?

A. Generic cost and performance estimates were developed to represent the various generation technologies relied upon in each of the plans to meet the RAP capacity needs. Company witness Greg Ford discusses how the generic resource estimates for thermal generation technologies were developed. I address how the generic resource estimates for renewable and battery technologies were developed later in my testimony.

Each of the nine plans was then modeled separately within a Strategist computer model representation of the Public Service electric system for years 2011-2050 using a modeling approach consistent with that used by the Company and approved by the Commission in Docket Nos. 07A-447E and 10M-245E. The Public Service system representation included the planned addition of approximately 900 MW[2] of wind generation and 60 MW of solar PV by the end of 2012 as well as the planned actions approved by the Commission in proceedings for the Clean Air – Clean Jobs Act.

Once cost estimates were developed for each plan under what are referred to as "starting assumptions", Strategist was then used to estimate the PVRR of each plan under a range of different assumptions concerning natural gas prices, carbon proxy cost, tax incentives, and electric sales.

Q. HOW DID THE COST OF THE LEAST-COST BASELINE CASE AND ALTERNATIVE PLANS COMPARE WITH ONE ANOTHER?

A. As discussed earlier, the least-cost baseline case had the lowest PVRR under the starting assumptions for natural gas prices, carbon proxy cost, tax incentives, and electric sales. The other eight alternative plans resulted in higher PVRR costs in the range of $98 million to $881 million. Section 2.8 of ERP Volume 2 Technical Appendix provides a detailed discussion of the cost differences between the alternative plans.

Q. DO YOU CONSIDER THE LEVEL OF HIGHER PVRR COSTS TO BE MATERIAL?

A. Yes. This question of what constitutes a material PVRR cost difference between plans arises in each resource planning docket. Parties often compare the PVRR cost differences between different plans with the total plan PVRR over the Planning Period. This type of comparison most always depicts the cost deltas between plans as a very minor percentage of the total Planning Period costs. Parties have used this type of comparison to argue in favor of higher 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 level of costs that are under consideration in this 2011 ERP, or what I refer to as being "in play". For example, what is "in play" among the alternative plans in this ERP is the roughly 300 MW needed to meet the RAP capacity needs. Using a levelized energy cost of $75/MWh[3] one can estimate the Planning Period PVRR for 300 MW[4] to be in the range of $680 million. Gauging the $98 million to $881 million of added costs in the alternative plans against the $680 million

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[2] 250 MW Cedar Creek II, 252 MW Cedar Point, 200 MW Limon I, and 200 MW Limon II
[3] See Figure 1.5-1 of Volume 1, excluding the 10% ITC Solar Thermal LEC
[4] Assuming a 45% annual capacity factor a 300 MW resource would produce 1,182 GWh/year.

"in play" provides a more useful view of whether these added costs are material.

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

A. With the exception of the Production Tax Credit ("PTC") wind sensitivity and the "Early CO_2" price sensitivity, the PVRR cost of all eight alternative plans remained higher than those of the least-cost baseline case. The PTC wind sensitivity included an assumption that the price of wind dropped 44% from \$68/MWh down to \$38/MWh as a result of an extension of the Production Tax Credit for wind. With this assumption, alternative plans A2, A3, A4, B2, B3, and B4 show lower PVRR costs than the least-cost baseline case. The "Early CO_2" sensitivity included an assumption that starting in year 2017, emissions of CO_2 would be priced at \$20/ton and would escalate at 7% annually to the end of the planning period. With this assumption, alternative plans A2, A3, B2 and B3 showed lower PVRR costs than the least-cost baseline case.

Q. ALTERNATIVE PLAN B2 INCLUDES 800 MW OF ADDITIONAL WIND. CAN THE COMPANY ADD ANOTHER 800 MW OF WIND TO ITS SYSTEM DURING THE RAP WITHOUT JEOPARDIZING SYSTEM RELIABILITY?

A. A group of Xcel Energy employees from system operations, transmission operations, gas planning and resource planning investigated how much wind can be added without jeopardizing reliable system operation.[5] They were

[5] See Section 2.14 of the Volume 2 Technical Appendix.

unable to identify an absolute level of wind on the system below which operations are reliable and above which they are not. Through this work effort the Company did conclude, however, that our current commitments, over 2,100 MW of wind generation operating on our system by the end of 2012, will in and of themselves increase system operational challenges. The degree to which these challenges present themselves won't be known until we gain actual experience operating the system with 2,100 MW of wind generation.

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

A. Yes. This was done by taking the deferred Renewable Energy Standard Adjustment ("RESA") balance presented in the 2014 RES Compliance plan and assigning that estimate to the least-cost baseline case. The additional costs of increased renewable resources in alternative plans A2, A3, B2, and B3 over those of the least-cost baseline case were added to the least-cost baseline case deferred RESA balance. The resulting impact to the deferred RESA balance is illustrated in Figure 1.5-4 of ERP Volume 1. RESA impacts were not calculated for alternative plans A4, A5, B4, and B5 since a portion of the additional costs in these plans were the result of adding the generic Section 123 resource technologies (batteries and solar thermal resources), which do not impact the RESA.

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

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

1) The fact that the least-cost baseline case selects gas-fired combustion turbines (a.k.a. peaking resources) to meet our resource need is an indication that our existing and planned generation resources will be capable of supplying the system energy needs in a cost-effective manner and that the Public Service system needs additional low cost capacity to achieve the desired level of planning reserve margin through the entire RAP. Low capital cost resources such as combustion turbines were selected to meet the roughly 290 MW of need for additional generating capacity.

2) Adding more renewable or Section 123 resources to the system is expected to result in added costs and, in the case of renewable resources, is expected to place increased pressure on the negative RESA deferred balance. This result is not unexpected when one considers the level of renewables that will be on the Company system by the end of 2012 and the lower prices being projected for natural gas. Continued additions of utility-scale renewable energy resources, such as wind and solar, are expected to provide diminishing energy cost savings because each renewable increment tends to displace lower cost fossil-fired energy. Much of the value renewable energy brings to the system is the result of decreasing the amount of fossil-fired energy that is needed to serve load. To the extent the $/MWh price of the renewable energy is lower than the $/MWh price of the fossil-fired energy it displaces, there will be a cost savings. As more and more renewables are added, the $/MWh cost delta between the renewable energy and the fossil-fired energy it displaces gets

smaller and smaller. This effect is diminished energy cost savings and eventually increased energy costs.

3) The Company should not propose that a portion of the RAP capacity need be "set aside" for additional renewable generation resources or for additional Section 123 resources. The Company does not need any additional wholesale DG or non-DG renewable resources to comply with the RES for several years beyond the RAP. The costs and benefits of all generation technologies including renewable generation resources and Section 123 resources should instead be evaluated within the Phase 2 competitive solicitation process.

Q. IS THE COMPANY ASKING THE COMMISSION TO ENDORSE EITHER THE LEAST COST BASELINE PLAN OR ONE OF THE EIGHT ALTERNATIVE PLANS IN THIS PHASE I PROCESS?

A. The Company presents the alternative plans in compliance with Commission rules. But the Company's preferred plan is to acquire resources to meet our resource need through an All-Source RFP, giving preference to shorter term resource proposals, as I discuss next.

V. <u>PHASE 2 COMPETITIVE SOLICITATION PROCESS</u>

Q. PLEASE SUMMARIZE THE COMPANY'S PLAN FOR ACQUIRING ADDITIONAL RESOURCES.

A. The Company proposes that a competitive solicitation process be used to acquire the additional generation resources needed to meet the projected capacity needs for the seven-year RAP (October 2011 – October 2018). This process would involve an All-Source Solicitation or RFP, allowing all resource technologies to bid against one another.

Q. PLEASE PROVIDE AN OVERVIEW OF THE BID EVALUATION PROCESS.

A. The process will involve three primary activities: 1) bid processing and initial due diligence, 2) static economic screening, and 3) computer modeling. The overall process will be the same as that employed by the Company and the Independent Evaluator in the 2007 ERP. The 2011 ERP, however, will include an additional bid evaluation step in which the Company will provide bidders that have been advanced to computer modeling with information on how their bid will be represented in that modeling process.[6] A more detailed description of the bid evaluation process is contained in Sections 1.7 of ERP Volume 1 and Section 2.9 of ERP Volume 2.

Q. WILL THE COMPANY BE SUBMITTING ANY COMPANY SELF-BUILD PROPOSALS?

A. It is my understanding that the Company intends to provide sufficient self-build proposals in the Phase 2 process to meet the entire resource need. These Company proposals will be compared against the bids offered from other entities. Company proposals will be assigned the same set of operation and maintenance costs, transmission interconnect and transmission delivery costs as the bids from IPPs and other utilities. The capital costs of Company proposals will be evaluated at their expected values.

[6] In accordance with Commission rule 3613(a)

VI. ARAPAHOE 4 AND CHEROKEE 4

Q. HOW WILL THE COMPANY ADDRESS THE COMMISSION CACJA ORDER TO PRESENT ALTERNATIVES TO RUNNING ARAPAHOE 4 AND CHEROKEE 4 ON GAS IN THE 2011 ERP?

A. Public Service proposes this be done through a process that would occur prior to the computer modeling of All-Source RFP bid portfolios. This process would consider bids from existing dispatchable gas-fired generation facilities received in response to the RFP as potential alternatives to running Arapahoe 4 and Cherokee 4 on gas. For any individual bid or group of bids to be eligible for consideration as potential alternatives, they must provide approximately the same MW amount of firm generation capacity as either Arapahoe 4 or Cherokee 4, or both. For Arapahoe 4, bids must offer this capacity through at least 12/31/2023, but no longer than 12/31/2025. For Cherokee 4, bids must offer this capacity to 12/31/2025 but no later. The analysis of potential alternatives will focus on a comparison between the $/kW-mo fixed costs of Arapahoe 4 and Cherokee 4 with the $/kW-mo fixed cost offered by eligible bids. Additional information regarding this evaluation process is contained in Section 1.7 of ERP Volume 1. To the degree the bids under consideration offer higher or lower heat rates than the heat rates of Arapahoe 4 and Cherokee 4, the fixed capacity cost of such bids will be adjusted up or down to reflect the value of that heat rate differential.

Q. PLEASE ELABORATE ON THE COMPONENTS OF "FIXED COST" OF CAPACITY.

A. The term “fixed costs” in this regard refers to generating unit costs that will be incurred irrespective of how often the unit generates electricity. For Arapahoe 4 and Cherokee 4, fixed costs would include items such as staff salaries and ongoing maintenance costs. For bids, fixed costs would be reflected by the $/kW-mo capacity price offered by bidders[7].

Q. HOW WILL DIFFERENCES IN HEAT RATE BE REFLECTED IN THIS ASSESSMENT?

A. Differences in heat rate will be represented as either a $/kW-mo adder or credit to the capacity price offered in bids. Table JFH-1 illustrates how this adder or credit will be determined. Note that the values in JFH-1 are for illustration purposes only.

Table JFH-1

	Firm MW	Annual CF	Annual Generation MWh
Arapahoe 4	109	2%	19,097

A	B	C	D	E	F	G	H
109 MW Arapahoe 4 Heat Rate (btu/kWh)	100 MW Gas Bid A Heat Rate (btu/kWh)	Heat Rate Difference (btu/kWh)	2014-2023 Average Gas Price ($/mmbtu)	Energy Cost Difference ($/MWh)	2014-2023 Average Arapahoe 4 Generation MWh	Gas Bid A Heat Rate Value $000	Gas Bid A Heat Rate Value ($/kW-mo)
11700	9000	2700	$ 7.00	$ 18.90	19,097	$ 331,128	$ 0.28

In this example, a 100 MW existing gas-fired generator with a 9,000 btu/kWh heat rate would receive a $0.28/kW-mo credit applied to its capacity price within this assessment.

7 $/kW-mo capacity prices are provided by bidders in Form D1 of the Dispatchable RFP.

VII. RENEWABLE AND BATTERY TECHNOLOGY ESTIMATES

Q. PLEASE SUMMARIZE HOW THE GENERIC ESTIMATES WERE DEVELOPED FOR RENEWABLE AND BATTERY TECHNOLOGIES USED IN DEVELOPING THE ALTERNATIVE PLANS.

A. The $/MWh estimates for renewable wind, solar PV, and solar thermal with storage technologies were developed as follows:

100 MW Non-PTC Wind – generic non-PTC wind pricing was set equal to the PTC-eligible wind pricing plus $30/MWh to reflect the economic value of the lost PTC. This $30/MWh adder is consistent with information provided to the Company in prior wind RFPs in which bidders were asked to provide both PTC-eligible and non-PTC-eligible pricing.

25 MW Solar PV (30% ITC) – generic PV (30% ITC) pricing estimates were developed based on cost and performance information received from recent Public Service RFPs and current installed costs for projects funded under the Company's Solar*Rewards programs. Declining costs consistent with those indicated in a May 6, 2010 Deutsche Bank PV study were applied to the Company's estimate of current installed costs to develop generic 30% ITC PV.

50 MW Solar Thermal with Storage (10% ITC) - generic solar thermal with storage (10% ITC) was set to 125% of the 50 MW (30% ITC) pricing.

125 MW Solar Thermal with Storage (10% ITC) - generic solar thermal with storage (10% ITC) was set to 125% of the 125 MW (30% ITC) pricing.

25 MW batteries - generic battery pricing of $3,000/kW of discharge capacity was based on EPRI cost reports as well as market information obtained by

Xcel Energy's battery storage activities as described in Section 2.2 of the ERP Volume 2 Technical Appendix.

Q. HOW WERE THE GENERIC ESTIMATES DEVELOPED FOR PURPOSES OF PERFORMING SENSITIVITY ANALYSES ON THE ALTERNATIVE PLANS?

A. The $/MWh estimates for renewable wind, solar PV, and solar thermal with storage technologies used in performing various sensitivity analyses of the alternative plans were developed as follows:

<u>100 MW PTC Wind</u> - generic PTC-eligible wind pricing estimates were developed based on cost and performance information Public Service received from its 2011 Wind RFP. A capital cost of $1925/kW (2011$), a fixed O&M cost of approximately $28/kW annually, and an annual capacity factor of 47.5% were assumed. Inflating the capital cost and fixed O&M costs to a 2017 in-service date resulted in a levelized wind cost of $38/MWh.

<u>25 MW Solar PV (10% ITC)</u> - generic PV (10% ITC) pricing estimates were developed in the same manner as the 30% ITC generic estimates but with an assumption of a 10% ITC.

<u>50 MW Solar Thermal with Storage (30% ITC)</u> - generic solar thermal with storage (30% ITC) was based on indicative pricing levels received in the 2009 All-Source RFP and DOE cost reduction targets.

<u>125 MW Solar Thermal with Storage (30% ITC)</u> – generic solar thermal with storage (30% ITC) was based on indicative pricing levels received in the 2009 All-Source RFP and DOE cost reduction targets.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

James F. Hill

Statement of Qualifications

I graduated from Colorado State University in 1983 with a Bachelor of Science degree in Natural Resource Management and in 1995 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 Energies Services Inc. for 27 years. I began my employment in 1984 at Public Service Company of Colorado's Fort St. Vrain Nuclear Generating Station in the Technical Services and Licensing Department. In August 1992, I joined Public Service Company of Colorado's System Planning Department where I performed resource planning functions, as a Planning Engineer, a Senior Resource Planning Analyst, Manager of Resource Planning and Bidding and now Director of Resource Planning and Bidding with a focus on Public Service Company of Colorado.

As the Director of the Resource Planning and Bidding Group, I have responsibility for overseeing the Company competitive resource acquisition processes as well as the various technical analyses on the resource options that are available to Xcel Energy's operating companies for meeting customer demand.

I have testified before the Colorado Public Utilities Commission regarding electric resource planning issues in numerous dockets.