**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 APPROVAL OF ITS	**) PROCEEDING NO. 21A-______E**
2021 ELECTRIC RESOURCE PLAN AND	**)**
CLEAN ENERGY PLAN	**)**

DIRECT TESTIMONY AND ATTACHMENT OF

JON T. LANDRUM

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

March 31, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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2021 ELECTRIC RESOURCE PLAN AND	**)**
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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
2021 ERP & CEP	2021 Energy Resource Plan and Clean Energy Plan
CEP	Clean Energy Plan
CEPR	Clean Energy Plan Rider
CO_2	Carbon
Commission	Colorado Public Utilities Commission
DER	Distributed Energy Resources
ECC	Economic Carrying Charge
ELCC	Effective Load Carrying Capability
ERP	Electric Resource Plan
L&R	Load and Resources
MPUC	Minnesota Public Utilities Commission
MW	Mega Watts
NPV	Net Present Value
NWPP	Northwest Power Pool
O&M	Operations and Maintenance
Pathway Project	Colorado's Power Pathway Project
PPA	Power Purchase Agreement
Public Service or Company	Public Service Company of Colorado

Acronym/Defined Term	**Meaning**
RAP	Resource Acquisition Period
RFI	Request for Information
RFP	Request for Proposal
SB 19-236	Senate Bill 19-236
SCC	Social Cost of Carbon
WECC	Western Electricity Coordinating Council
XES	Xcel Energy Services Inc.
Xcel	Xcel Energy Inc.

**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 APPROVAL OF ITS 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN	**))) PROCEEDING NO. 21A-______E))**

DIRECT TESTIMONY AND ATTACHMENT OF JON T. LANDRUM

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jon T. Landrum. My business address is 1800 Larimer Street, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Manager of Resource Planning Analytics. 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 the "Company"), along with the other 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 Manager of Resource Planning Analytics, I lead the analytical team responsible for conducting resource planning-related quantitative analysis for the Xcel Energy companies, including Public Service. I also support the Company's Transmission Planning and Business Relations divisions. I have been in my current role for eight years, and prior to this role I served as a manager in the Risk Management department of Xcel Energy for seven years. I was both a manager and an analyst in the resource planning organization of my previous employer, TECO Energy, for seven years. I have testified before utility regulatory agencies of Florida, Minnesota, and Colorado on matters pertaining to resource planning and risk management. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support the Company's 2021 Electric Resource Plan and Clean Energy Plan ("2021 ERP & CEP") from a resource planning analytics perspective. First, I discuss the Company's new modeling tool that we are using for this 2021 ERP & CEP called EnCompass. The EnCompass model replaces the Strategist model that the Company used for several of its previous Electric Resource Plan ("ERP") cycles. I provide an overview of EnCompass and explain its capabilities and how the functionality of the EnCompass model differs from the Strategist model. I also describe how the model runs were performed for purposes of the Company's Phase I modeling.

Next, I describe how we compiled data from numerous Company departments to "set the stage" for the EnCompass modeling. I explain several of the key inputs and assumptions that went into the model. These include, for example, inputs and assumptions regarding ongoing costs of the system, generic resources, capital cost recovery mechanisms, workforce and community transition, transmission-related costs, cost of carbon, and system reliability. Finally, consistent with the Commission's electric resource planning processes, I explain how the Company will incorporate updated modeling assumptions consistent with the Colorado Public Utilities Commission's ("Commission") Phase I Decision prior to the Phase II competitive acquisition and bid evaluation process.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring Attachment JTL-1, which is a whitepaper on the operation of the EnCompass resource planning model that was prepared by the model's vendor, Anchor Power Solutions.

II. ENCOMPASS MODELING TOOL OVERVIEW

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my Direct Testimony is to provide an overview of the EnCompass modeling tool the Company is using for this 2021 ERP & CEP. I explain the capabilities of EnCompass and how the functionality of the new EnCompass model differs from the Strategist modeling tool the Company used in previous ERPs.

Q. IS THE COMPANY USING A NEW MODELING TOOL IN THIS ERP VERSUS WHAT IT HAS BEEN USED IN PREVIOUS ERPs AND VARIOUS OTHER PROCEEDINGS BEFORE THE COMMISSION?

A. Yes, beginning in early 2020, the Company discontinued use of its previous planning model, Strategist, which had been used for over 20 years. Strategist was no longer being supported or upgraded by its vendor, and with the increasing complexity of the electric system, including reliance on energy storage and increasing levels of intermittent generation (primarily wind and solar), it was necessary to find a more modern model that is better able to analyze these complex factors. The Company selected the EnCompass planning model from Anchor Power Solutions as the replacement tool for resource planning modeling across all of the Xcel Energy jurisdictions.

Q. IS THIS THE COMPANY'S FIRST USE OF ENCOMPASS IN COLORADO?

A. Yes.

Q. HAS THE COMPANY USED THE ENCOMPASS MODEL IN ITS OTHER OPERATING COMPANIES?

A. Yes. In the past year, Xcel Energy has used the model in several filings in its upper Midwest service territory, including a supplement to its Upper Midwest Integrated Resource Plan in June, 2020, before the Minnesota Public Utilities Commission ("MPUC") and several renewable resource acquisition dockets in both Minnesota and North Dakota.

Q. HOW DID THE COMPANY SELECT ENCOMPASS?

A. The Company conducted an open request for information ("RFI") process and sent the RFI to approximately fifteen vendors that offer models that could potentially be used for resource planning purposes. From the responses, four vendors were selected to present a one-half day overview of their model to the review team during an on-site visit. The candidates were then narrowed to two finalists and the Company obtained a working version of each model and conducted extensive training and internal evaluation of each model. From this process, EnCompass emerged as the clear preferred model across numerous qualitative and quantitative evaluation criteria. Several factors led to the selection of EnCompass, including the ability to easily share input and output data in straightforward Excel spreadsheet format, as well as the vendor's willing ness to offer regulatory bodies a reduced cost license if they wish to run the software themselves.

Q. DID THE COMPANY INFORM STAKEHOLDERS AND THE COMMISSION OF THE COMPANY'S SELECTION OF THE NEW ENCOMPASS MODEL PRIOR TO FILING ITS 2021 ERP & CEP?

A. Yes. In 2019 and 2020, the Company met with then-Commissioners and Advising Staff, as well as Trial Staff to discuss the model selection process and the EnCompass model itself. Additionally, the Company informed stakeholders of its selection of the EnCompass model in comments filed in the ERP Rulemaking proceeding (Proceeding No. 19R-0096E) in early 2019. As noted in our initial comments filed in that proceeding, the Company considered concerns and comments previously expressed by stakeholders, the Independent Evaluator, and the Commission with regard to improving the functionality and transparency of the modeling process moving forward. As a result, Public Service discussed in its comments that it selected the new EnCompass model – a model which several stakeholders advocated for in their respective comments--to address the expressed need for more detailed modeling capabilities in the complex and evolving resource planning environment.[1] I also facilitated a discussion at stakeholder workshops on December 13, 2019 and November 6, 2020 to introduce the EnCompass model to interested stakeholders and previewed how the model would be used for the Company's 2021 ERP & CEP.

[1] *See* Initial Comments of Public Service Company of Colorado filed on March 29, 2019 in Proceeding No. 19R-0096E; and, Reply Comments of Public Service Company of Colorado filed on April 19, 2019 in Proceeding No. 19R-0096E.

Q. HOW DOES ENCOMPASS DIFFER FROM STRATEGIST?

A. Both models serve the same ultimate purpose, which is to develop and analyze capacity expansion plans and associated production costs of those plans under a variety of scenarios and sensitivities. The primary difference between the two models is in the internal algorithms and methodologies they use to accomplish the same purpose. Strategist used a more simplistic numerical process to complete these tasks. Specifically, it used a more general "load duration curve" and "typical week" approach to simulate the dispatch of the system and used a dynamic programming methodology to attempt to find optimal expansion plans. At a high level, the Strategist methodology was to find every possible combination of resources, run all possible plans through a dispatch process, and then rank them by cost to determine the most economic plan. In actuality, it is not feasible to compute the costs for every possible plan due to the sheer number of possible plans, so Strategist used some simplification methods to reduce the problem size.

EnCompass, on the other hand, uses a more modern numerical methodology called mixed-integer programming. The model simultaneously solves the capacity expansion plan, production costs, environmental constraints and ancillary service markets in a single simulation that "converges" on the optimal solution to all these factors in a single co-optimization process.[2] In addition, the

[2] A "solve" means a single problem matrix that is set up and solved in a single step. For example, in the Phase I capacity expansion step, a single problem matrix spanning 2024-2050 is created and the model resolves this matrix into a single solution for added generics, dispatch costs, CO_2 production and ancillary services for the entire period at once. As a comparison, in different uses, the model might also be tasked to "solve" a single year's production costs in a single solution, or even only a week's production costs in a single solution.

EnCompass model conducts production costing in a true hourly chronological manner, enforcing constraints such as start times/costs and ramp rates for resources, which requires a chronological dispatch to fully capture. Attachment JTL-1 to my Direct Testimony is a whitepaper from the vendor of EnCompass that describes some of these differences and how the mixed integer process works in much greater detail.

Q. ARE THERE VARIOUS "SETTINGS" USED IN ENCOMPASS THAT ALLOW THE MODEL TO BE RUN IN DIFFERENT WAYS?

A. Yes. The primary settings relevant to the ERP concern the granularity of the time blocks modeled and the options for determining unit commitment. The EnCompass model has the capability to model every hour of every year of the modeling period in a full chronological process – this is what is typically termed an "8760" dispatch, meaning every hour of the year is modeled. EnCompass also has settings to reduce the overall problem size by looking at fewer days and/or fewer hours per day by aggregating hours into a single block (i.e., considering 12 A.M. – 4 A.M. as a single simulation block versus four discrete hours). In the Phase I modeling presented in this filing, the Company modeled the full 24 hours in each day and did not use the hourly aggregation feature. However, different settings for the number of days to model and commitment logic were used depending on the simulation type.

Q. WHAT DO YOU MEAN BY "SIMULATION TYPE"?

A. For modeling the Public Service system, we employ a multi-step process to arrive at a fully developed solution for a given scenario. We first perform capacity expansion runs to determine the new resource portfolio additions. Then a production cost run is completed on this plan using more detailed settings. Internally, we refer to this process as Step 1 and Step 2. To study detailed system operations at an hourly level, we can also perform a third "detailed hourly commitment" analysis.

Q. PLEASE DESCRIBE STEP 1.

A. The Step 1 simulation is development of the capacity expansion plan. Since this is a large problem to solve, with the determination of type and timing of new resources being considered along with the commitment, dispatch, and other processes, it is necessary to reduce the problem size to a level manageable by standard business computer processors. Additionally, the problem must solve all years of the planning period at once so that the long-term impact of the resources being selected are fully known. It is simply not possible to simulate 30 years of full 8760 dispatch hours in a single "solve." Thus, for the Step 1 capacity expansion runs, we reduce the number of days to two days per calendar month; one representing an on-peak (i.e., Western Electricity Coordinating Council ("WECC") defined Monday-Saturday) day and the other representing an off-peak day (i.e., WECC defined Sunday). The model weights these days internally by the actual number of on- and off-peak days in the month. These two days per month are solved as two separate fully chronological 24-hour periods. We also employ the partial commitment logic for Step 1 to further reduce the problem size. The partial commitment logic is explained in Attachment JTL-1.

Q. PLEASE DESCRIBE STEP 2.

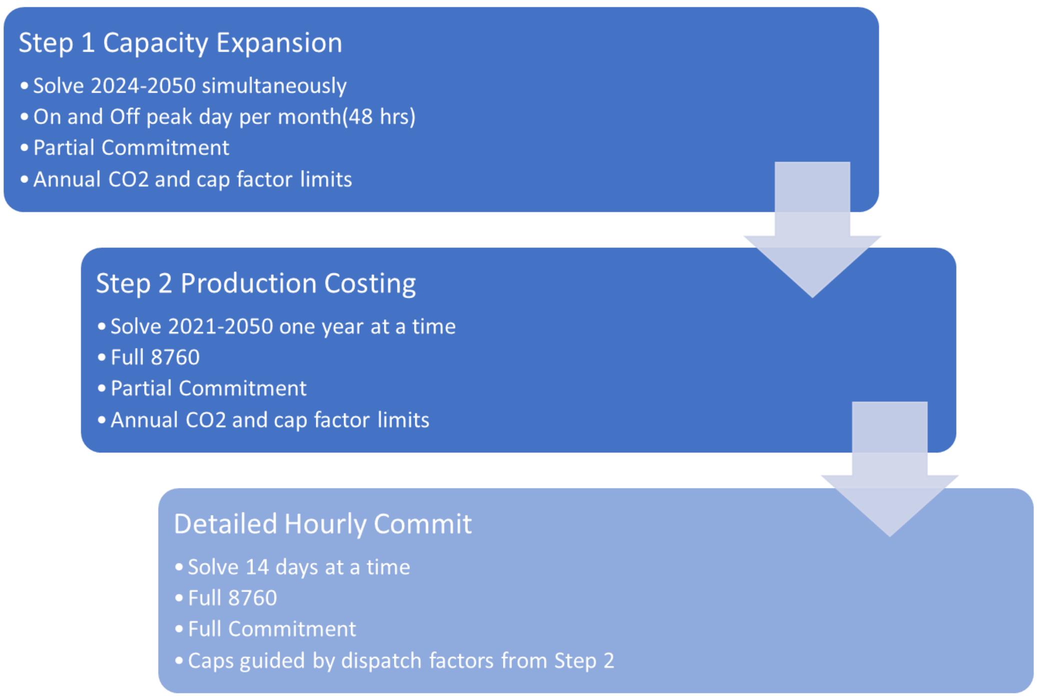
A. The next step, Step 2, is to determine the production costs of the chosen plan. In the Public Service modeling, we have several annual limits and caps that have to be enforced, including the 80 percent carbon cap in the Clean Energy Plan ("CEP") scenarios and some annual capacity factor limitations on certain resources, such as batteries and Comanche 3, for the plan that contemplates limiting its dispatch. These limits can only be solved if the full year (8760 hours) is run as a single simulation – which is also a very large problem to solve in a single pass. In order to do this in a single solution, the same simplifications on the commitment process are used here as in Step 1.

Q. PLEASE DESCRIBE THE DETAILED HOURLY COMMITMENT.

A. The detailed hourly commitment, used for studying the hour-by-hour operation of the system and evaluate real-time reliability, is the full 8760 production cost runs with the full commitment logic, which produces results using the full capabilities of the model. These full commitment logic runs are typically done in 7-14 day increments, with the model "solving" these one or two weeks, then moving sequentially to the next weeks until the full period has been solved. The problem size is too large with the full commitment logic to solve an entire year at once, so there is no way for the model to know how to allocate the "carbon budget" (for instance) amongst a year since it is only solving a couple of weeks at a time and has no foreknowledge of the remainder of the year. For these runs the model "inherits" some internal cost factors from the Step 2 run that allow it to relatively accurately enforce the annual limits that were fully imposed in the Step 2 runs.

However, this process is not completely precise, and it there typically is some "slippage" in the annual carbon caps and/or operating limits seen in the annualized results of these runs. Figure JTL-D-1 below show these steps and a summary of the setting and differences.

Figure JTL-D-1



Q. WHAT IS THE DIFFERENCE BETWEEN THE FULL COMMITMENT LOGIC USED IN THE DETAILED HOURLY COMMITMENT RUNS AND THE PARTIAL COMMITMENT LOGIC USED IN STEPS 1 AND 2?

A. The options for unit commitment allow for the simulation to be simplified for runtime or size (memory) concerns. Full Commitment is the standard setting, which forces the number of units online, startups, and shutdowns to be integer values (whole numbers). The Partial Commitment setting allows the number of units online, startups, and shutdowns to be continuous values, which allow for a fraction of a unit to be started and online. For example, if an interval shows 0.4 units online, this is equivalent to using 40 percent of the values for capacities, ramp rates, and commitment costs. If the next interval shows 0.6 units online, this is the same as starting up another unit with 20 percent more of those values. Minimum Uptime and Downtime requirements are still enforced for each fractional block started up and shut down. This option has the advantage of keeping all costs and constraints intact, but bypasses the step in the optimization that searches for the best way to round the units online up or down, thus reducing runtime.

Q. HOW WERE THE RUNS PERFORMED FOR THE PHASE I MODELING IN THIS ERP?

A. The majority of the preliminary draft runs were concluded at the Step 2 phase. Due to the complexity of the Public Service model, largely driven by the ancillary service requirements that I will explain later, and the limited amount of interchange with outside markets (requiring the system to be self-reliant), the detailed hourly commitment analyses take a very long time to complete. Generally, we see run times of 24-36 hours per each year being solved for these runs (i.e., a 30-year full commitment run could take 30*24 hours or 30 days to finish). Additionally, the annual limits are not perfectly enforced for these runs. For these reasons, the Company determined that the Step 1 and 2 runs were the appropriate analysis methods for the Phase I filing.

Q. DO STEP 2 RUNS PROVIDE THE LEVEL OF INFORMATION NEEDED FOR DETERMINING WHETHER TO PROCEED FOR COMPOSING A WELL-CONSIDERED PHASE I?

A. Yes, for several reasons. First, we are evaluating long time periods (30 plus years) and are primarily concerned with annual data, not hourly granularity, for determining the key metrics of interest, primarily costs and carbon emissions. The Partial Commitment logic is more suitable for producing long term analytical results—it provides more of an "expected value" result given the static inputs for load and renewable shapes, the long period studied, and the ability to solve the full year as a single problem. The detailed hourly commitment runs do offer a valuable look, however, when studying the system operations at a more granular hourly level. The Company's Commercial Operations team used results from these runs to evaluate system reliability and the expected hourly operations of the system for selected scenarios and years as discussed further in the Direct Testimony of Company witness Mr. John T. Welch.

Q. WHAT OTHER RUNS WERE COMPLETED AND WHAT WERE THE RESULTS?

A. The Company performed detailed hourly commitment runs for 2030 and 2040 for both the ERP (reference) scenario and the Preferred Plan under both the social cost of carbon ("SCC") and $0/ton carbon ("$CO_2$") cost assumptions to analyze the hourly operations of the system (Scenarios $0/ton 1, $0/ton 7, SCC 1 and SCC 7[3]). In general, these runs indicated a very small difference between the results

[3] These scenarios are described by Company witness Mr. James F. Hill.

from Step 2. A comparison of these results is shown below in Table JTL-D-1 and the results for both costs and carbon are very similar between the two runs for the studied years. As discussed further in Volume 2, the Company intends to explore the use of the full commitment logic in Phase II when the model is simplified by only optimizing through 2030. The Company proposes to utilize the best practicable methods to evaluate bid portfolios after this further exploration, but we will use Step 2 runs at a minimum.

Table JTL-D-1

Annual Costs ($000)								
	SCC				$0 CO2			
	SCC 1	SCC 1 - Detailed Hourly Commitment	Delta	% Change	$0/Ton 1	$0/Ton 1 - Detailed Hourly Commitment	Delta	% Change
2030	2,299,193	2,307,861	8,668	0.4%	2,159,460	2,179,139	19,679	0.9%
2040	3,279,938	3,270,744	(9,194)	-0.3%	3,225,898	3,233,018	7,121	0.2%
	SCC				$0 CO2			
	SCC 7	SCC 7 - Detailed Hourly Commitment	Delta	% Change	$0/Ton 7	$0/Ton 7 - Detailed Hourly Commitment	Delta	% Change
2030	2,451,245	2,448,723	(2,522)	-0.1%	2,296,612	2,321,156	24,544	1.1%
2040	3,326,041	3,344,577	18,535	0.6%	3,187,347	3,200,122	12,774	0.4%

Carbon Emissions (Tons)								
	SCC				$0 CO2			
	SCC 1	SCC 1 - Detailed Hourly Commitment	Delta	% Change from 2005	$0/Ton 1	$0/Ton 1 - Detailed Hourly Commitment	Delta	% Change from 2005
2030	8,451,133	8,584,125	132,992	0.5%	10,198,746	10,325,287	126,541	0.5%
2040	6,789,544	6,935,653	146,109	0.5%	6,796,143	6,905,883	109,740	0.4%
	SCC				$0 CO2			
	SCC 7	SCC 7 - Detailed Hourly Commitment	Delta	% Change from 2005	$0/Ton 7	$0/Ton 7 - Detailed Hourly Commitment	Delta	% Change from 2005
2030	4,257,181	4,348,222	91,041	0.3%	5,220,731	5,246,761	26,030	0.1%
2040	3,335,820	3,738,326	402,507	1.5%	3,912,608	4,029,144	116,536	0.4%

III. KEY MODELING ASSUMPTIONS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I describe how the EnCompass model was set up and I explain the key inputs and assumptions that went into the model. Company witness Mr. James F. Hill provides more detail on the specific scenarios that were defined and studied, as well as the results from the modeling. I will cover the key inputs into the model and how they were incorporated.

Q. HOW HAS THE SYSTEM NEED BEEN DEFINED?

A. The base load forecast, as described by Company Witness Mr. John M. Goodenough, was input into the EnCompass model as the system energy and demand need. However, the load forecast typically includes forecasted distributed energy resources ("DER") as a reduction in system energy and demand needs. For purposes of modeling, the DER resources were removed from the load forecast and included in the EnCompass model as system resources, with appropriate adjustments to account for the avoidance of transmission and distribution losses provided by these resources.

Q. HOW WERE THE ONGOING COSTS OF THE EXISTING SYSTEM DEFINED?

A. Data is compiled from numerous departments to "set the stage" for the EnCompass modeling. First, forecasts of key cost and operational variables, including but not limited to, capacity, heat rate, outage rates, capital additions, and operations and maintenance ("O&M") for all existing generation units on the system are obtained (this includes the coal plants that are the primary focus of this analysis). For the various coal actions considered, separate forecasts were provided for each alternative (i.e., early retire, fuel conversion, limited/reduced operations). Then certain financial data including current (end of year 2019) book value, accumulated depreciation, and deferred taxes are incorporated. For the non-coal units, these data were converted into a revenue requirement stream using a tool outside of EnCompass and entered into the model as resolved revenue requirements. For the coal action alternatives, Company witness Mr. Scott A. Watson prepared the revenue requirements for the alternatives based on the applicable cost recovery approach, as he discusses in detail in his Direct Testimony.

Q. HOW WERE THE COSTS AND CHARACTERISTICS OF THE GENERIC RESOURCES DEVELOPED?

A. Mr. Hill provides a description of the source of the costs and performance characteristics of the generic resources used in the Phase I modeling in his Direct Testimony. Cost and performance details of the generic resources are also included in Volume 2. The generic resource data was input into EnCompass to create available “projects” (i.e., generation resources) to be used when developing capacity expansion plans.

Q. WERE THE GENERIC RESOURCES LIMITED IN THE MODELING?

A. Generic resources of all the defined types were generally allowed to be selected in any number and in any year. However, the Company did include a limit of additions by year in the early years of the resource acquisition period (“RAP”) to recognize both the expected timing of the ERP process and the availability of transmission interconnection ability in the near term. Specifically, the modeling did not allow generic resources prior to 2025 due to the expected timing of the Phase 1 process and limited combined wind and solar additions to 1,000 megawatts ("MW") per year for years 2025 through 2027 in recognition of the anticipated timeline for transmission buildout and associated interconnection availability. All limitations were removed for year 2028 and beyond.

Q. HOW WERE CAPITAL RECOVERY MECHANISMS FOR THE VARIOUS COAL ACTION ALTERNATIVES WITH ACCELERATED RETIREMENT DATES MODELED?

A. As Mr. Watson describes, for almost all scenarios the Company assumed that the remaining, or unrecovered, plant balance at the point of early retirement is transferred into a regulatory asset which is then amortized, or recovered, over a 10-year period. In the Company's Preferred Plan ($0/ton7, SCC7, SCC7A), the remaining balance of Comanche 3 in 2040 is securitized. As explained by Mr. Watson, for the proposed coal actions that underlie the Preferred Plan from a capacity need perspective, the Company is proposing the regulatory asset recovery treatment for Craig 2, Hayden 1, Hayden 2, and the retired portion of Pawnee. The Company is proposing to use securitization for Comanche 3 in 2040 and, if the Commission agrees, Public Service would file a separate application for a financing order in the future. Company witness Ms. Brooke A. Trammell discusses the series of regulatory events that would follow this ERP cycle with regard to securitization in more detail in her Direct Testimony.

Q. UNDERSTANDING THAT THE COMPANY IS ONLY PROPOSING THE USE OF SECURITIZATION FOR COMANCHE 3 UNDER ITS PREFERRED PLAN, HAS THE COMPANY DEVELOPED SECURITIZATION ESTIMATES FOR THE OTHER SCENARIOS AND ASSETS?

A. Yes—the Company thought this information was important to have in the record, and Mr. Watson developed securitization estimates for other assets and scenarios as well. The capital recovery mechanism has no impact on either the expansion plan or the dispatch of the system, so it is possible to create a "sensitivity" for other capital recovery strategies by simply adjusting the net present value ("NPV") costs from the existing model runs for the change in NPV due to the different cost recovery approach (i.e., accelerated depreciation, regulatory asset, or securitization). To illustrate this point, a comparison of using securitization for both Pawnee and Comanche 3 for the various scenarios versus the base assumption (regulatory asset) is shown in Table JTL-D-2 below:

Table JTL-D-2

SCC Optimized Portfolios
$0/ton 8760-dispatch
Reg Asset
50% ownership

Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
PVRR Utility Cost 2021-2055 ($M)	$ 38,814	$ 39,582	$ 39,429	$ 39,373	$ 39,450	$ 39,230	$ 39,306	$ 39,453
NPV CO2 2021-2055 ($M)	$ 8,625	$ 6,296	$ 6,719	$ 6,295	$ 6,234	$ 6,809	$ 6,646	$ 6,329
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 47,439	$ 45,877	$ 46,148	$ 45,669	$ 45,684	$ 46,040	$ 45,951	$ 45,782
PVRR Utility Cost 2021-2055 w/ Securitization ($M)	$ 38,814	$ 39,436	$ 39,337	$ 39,257	$ 39,336	$ 39,170	$ 39,284	$ 39,382
NPV CO2 2021-2055 ($M)	$ 8,625	$ 6,296	$ 6,719	$ 6,295	$ 6,234	$ 6,809	$ 6,646	$ 6,329
PVRR Utility Cost w/ Secur + NPV CO2 2021-2055 ($M)	$ 47,439	$ 45,731	$ 46,056	$ 45,553	$ 45,569	$ 45,979	$ 45,930	$ 45,711
Delta PVRR Utility Cost	$ -	$ (146)	$ (92)	$ (116)	$ (115)	$ (61)	$ (22)	$ (71)
Delta NPV CO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Delta PVRR Utility Cost + NPV CO2	$ -	$ (146)	$ (92)	$ (116)	$ (115)	$ (61)	$ (22)	$ (71)

$0/ton Optimized Portfolios
$0/ton 8760-dispatch
Reg Asset
50% ownership

Portfolio	$0/ton 1	$0/ton 2	$0/ton 3	$0/ton 4	$0/ton 5	$0/ton 6	$0/ton 7	$0/ton 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
PVRR Utility Cost 2021-2055 ($M)	$ 38,280	$ 38,875	$ 38,898	$ 38,692	$ 38,791	$ 38,913	$ 38,752	$ 38,898
NPV CO2 2021-2055 ($M)	$ 9,107	$ 7,051	$ 7,141	$ 6,924	$ 6,971	$ 7,027	$ 7,046	$ 6,758
PVRR Utility Cost + NPV CO2 2021-2055 ($M)	$ 47,387	$ 45,926	$ 46,039	$ 45,616	$ 45,762	$ 45,940	$ 45,798	$ 45,656
PVRR Utility Cost 2021-2055 w/ Securitization ($M)	$ 38,280	$ 38,729	$ 38,806	$ 38,576	$ 38,677	$ 38,853	$ 38,730	$ 38,827
NPV CO2 2021-2055 ($M)	$ 9,107	$ 7,051	$ 7,141	$ 6,924	$ 6,971	$ 7,027	$ 7,046	$ 6,758
PVRR Utility Cost w/ Secur + NPV CO2 2021-2055 ($M)	$ 47,387	$ 45,780	$ 45,947	$ 45,500	$ 45,647	$ 45,879	$ 45,777	$ 45,585
Delta PVRR Utility Cost	$ -	$ (146)	$ (92)	$ (116)	$ (115)	$ (61)	$ (22)	$ (71)
Delta NPV CO2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Delta PVRR Utility Cost + NPV CO2	$ -	$ (146)	$ (92)	$ (116)	$ (115)	$ (61)	$ (22)	$ (71)

Q. WERE REPRESENTATIVE COSTS FOR WORKFORCE TRANSITION AND COMMUNITY ASSISTANCE INCLUDED IN THE MODELING FOR THE ALTERNATIVE COAL PLAN FUTURES?

A. Yes. Certain representative cost estimates for the Company's workforce transition and community assistance plans, as discussed by Company witnesses Ms. Holly L. Stanton and Ms. Hollie J. Velasquez Horvath, respectively, were included in the modeling at the time the model was being developed in late 2020. For workforce transition plan costs, we used the costs provided by Ms. Stanton and included in the Workforce Transition Plan provided by the Company in this proceeding. For community assistance plan costs, on the other hand, we used the property tax revenue stream for a particular coal unit and left it in the model even where the coal unit retired early. We left the property tax revenue stream through the end of the unit's book life or the end of the planning period, whichever was sooner. These property tax revenues are meant to serve as a proxy for community assistance plan costs for a particular unit, as explained by Ms. Velasquez Horvath. Moreover—and importantly—as discussed by Ms. Stanton and Ms. Velasquez Horvath, the workforce transition and community assistance planning processes are iterative and ongoing. As a result, the costs incorporated in the model will be updated as these plans evolve and as associated costs are further defined.

Q. DID THE COMPANY MAKE ANY ASSUMPTIONS REGARDING UTILITY OWNERSHIP OF GENERATION RESOURCES IN THE PHASE I MODELING?

A. In the Phase I modeling, all generics were modeled using either an Economic Carrying Charge (“ECC”)[4] stream (for the thermal generics and storage) or an escalating $/MWh (for the renewables). Although this payment type is typically associated with power purchase agreement (“PPA”) contracts, there was no implicit assumption regarding PPA versus Company owned resources in the modeling. The use of a linear escalating cost over time for the generic resources aligns with the generally similar profiles of load growth, fuel price forecasts, etc. and can lead to a better optimization solution when the life of the resources extend beyond the planning period. For purposes of determining final costs and rate impacts, the Company adjusted 50 percent of the generic resources to have a capital revenue requirements profile that exactly matched the ECC profile on an NPV basis. Accordingly, there is a utility ownership assumption to align with Senate Bill 19-236 (“SB 19-236”) which does not affect the economics of the portfolios in Phase I generic modeling in total modeling period present value terms but does impact the annual cost deltas and NPV’s in the near term.

Q. HOW WERE TRANSMISSION-RELATED COSTS CAPTURED IN THE MODEL?

A. In the EnCompass model, all generics were assigned an estimated incremental proxy cost for network upgrades and interconnection costs. This was done so that

[4] An ECC stream in this usage is a series of costs that escalate at the general inflation rate (2% in this ERP) and present value to the same value as the present value of the revenue requirements for the project. It is similar to a “levelized cost” but escalates in nominal terms rather than being constant.

when making expansion plan decisions, the model had knowledge of the estimated incremental costs associated with each technology. In post-processing, the estimated revenue requirements of the Company's proposed Colorado's Power Pathway Project ("Pathway Project"), the details of which are discussed in the Direct Testimony of Company witness Mr. Hari Singh, were added to the output costs. Given this addition to the output costs, the incremental "generic" proxy transmission costs were removed from the first 5,000 MW of incremental wind and solar generic resources in every scenario. As discussed by Ms. Trammell, it is anticipated that these transmission costs would not be incrementally applied to resource bids that utilize existing transmission facilities or interconnect to proposed transmission with either a Certificate of Public Convenience and Necessity (e.g., Colorado's Power Pathway) or designated as bid-eligible planned transmission . A sensitivity was completed and presented in Volume 2 and the Direct Testimony of Company witness Mr. James F. Hill where the incremental transmission costs were not included in the capacity expansion optimization – in other words the transmission costs were considered sunk. This did change the RAP expansion plans somewhat. But it did not materially affect the relative economics (deltas amongst the plans) of the various scenarios tested. The Company anticipates that the methodology for Phase II treatment of transmission costs will be determined in this Phase I proceeding.

Q. WERE ANY OTHER ADJUSTMENTS MADE TO THE MODEL OUTPUTS TO DETERMINE RATE IMPACT?

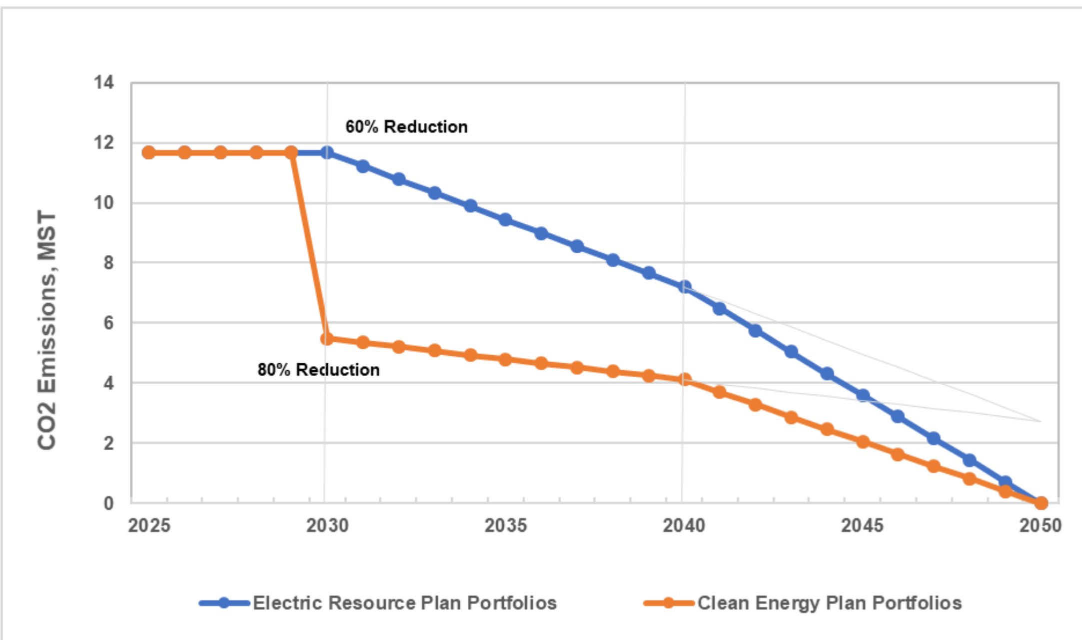
A. To determine overall rate impact, the model output was further adjusted to include an estimate of "balance of system" costs that are not included in the EnCompass model. These costs are primarily associated with the non-generation portions of the Public Service system including, for example, distribution system costs, administrative and general costs, transmission costs related to the existing system, as well as an estimate of Renewable Energy Standard Adjustment and Clean Energy Plan Rider costs, described by Company witness, Mr. Alexander G. Trowbridge, for the various scenarios.

Q. HOW WERE CARBON COSTS AND CAPS APPLIED IN THE PHASE I MODELING?

A. As Mr. Hill describes, for each of the eight coal action scenarios, the Company performed capacity expansion plans and production costs with a $0/ton carbon cost and with the SCC. To develop the SCC value for use in the Encompass modeling, we referenced the federal social cost of carbon, using the value calculated at a three percent discount rate, labeled as "3% Average" in the federal Technical Support Document. We used the values that are expressed in constant 2007 dollars per metric ton and converted those to nominal dollars per short ton to reflect the values we use in resource planning. After the conversion, the lowest value was $47 per nominal short ton, so we did not have to use SB 19-236's floor value of $46 per short ton. The expansion plan developed using the SCC was also dispatched with no carbon cost in the dispatch decision. A carbon cap was applied to all scenarios, with all of the CEP plans (scenarios 2-7) required to meet 80 percent carbon reductions by 2030 and then show continuous progress towards further reductions. On the other hand, Scenario 1 was required to maintain the level of carbon resulting from the approved portfolio in the Company's 2016 ERP (approximately 60 percent reduction) without going backwards, then continue to make progress from 2030 and beyond. In application, continuous progress was set up as a linear reduction on a path to 90 percent reduction by 2050 for the period of 2030-2040. Then, starting in 2041, all of the scenarios were required to accelerate the trajectory of CO_2 reductions to reach zero tons of carbon by 2050. A graphic representation of these caps is shown below in Figure JTL-D-2. During preliminary modeling, it was observed that the various stages of analysis, progressing from capacity expansion to production costing and detailed hourly commitment, resulted in increasing levels of carbon emissions for the same plan. This is due to the increasing level of granularity in the steps: proceeding to two days per month in capacity expansion to full 8760 analysis in the production costing, and then proceeding from partial to full commitment logic in the detailed hourly analysis. Thus, lower caps were input into the model for capacity expansion and production costing to ensure plans were selected that would meet the true caps under real-time operations. Specifically, the expansion plans were developed using 85 percent of the cap, and the subsequent production costing runs were completed using 95 percent of the cap.

As the Company has maintained in public discussion, we believe further technology and cost improvements, primarily surrounding the availability of carbon-free dispatchable resource options, are necessary to realistically attain a carbon-free electric system. As a proxy for this future development, the Company introduced the availability of a "clean fuel" (hydrogen) beginning in 2041. Hydrogen, priced at $20/mmbtu, was blended into the natural gas fuel supply at an increasing rate of 10 percent per year, ending at 100 percent in 2050. A sensitivity was also completed using half of the base hydrogen value, or $10, to verify that the assumption regarding hydrogen has minimal impact on the RAP expansion plan.

Figure JTL-D-2



Q. WAS A REQUIREMENT FOR A SECURE FUEL SUPPLY INCLUDED THE MODELING?

A. Yes, as described by Mr. Welch, the modeling included costs for both firm fuel supply and incremental gas storage needs. A proxy cost for firm gas supply was included on all incremental gas resources in the modeling as part of the optimization of thermal generics. The costs associated with incremental gas storage were not able to be included in the optimization due to the structure of the analysis supporting the cost estimates, but were added on to the portfolio costs as a post-processing adjustment. In general, the storage costs make up less than half of one percent of the total NPV of the plans, and are also fairly consistent across all scenarios, thus there is minimal impact implementing this as a post-processing adjustment.

Q. WHAT RELIABILITY AND RESERVE CONSTRAINTS WERE USED IN THE MODEL?

A. As discussed in Volume 2 and the Direct Testimony of Company witnesses Mr. Welch and Mr. Kent L. Scholl, the Company included requirements for operating reserves, wind-driven flex reserves, and solar-driven regulation in the modeling in accordance with the Northwest Power Pool ("NWPP") requirements and the Flex Reserve Study provided with this ERP.[5] In addition, the application of the planning

[5] The Flex Reserve Study and Supplement to the Flex Reserve Study are provided as Attachment KLS-3 and Attachment KLS-4, respectively, to the Direct Testimony of Company witness Mr. Kent L. Scholl.

reserve margin and Effective Load Carrying Capability("ELCC") study results in the modeling is also a reliability constraint.[6]

The operating reserves were calculated on an hourly basis through 2050 using the NWPP formula and developed hourly forecasts of the variables involved that are derived from, or consistent with, the other relevant data already in the model. Of this hourly operating reserve, 50 percent was required to be sourced from spinning or quick start units.

Both Flex and Regulation requirements are dependent on the amount of wind and solar (respectively) that are on the system. Ancillary service requirements are defined on an hourly basis in the modeling, but they are input data that must be locked prior to model execution. Thus, there is a circular logic problem where the ancillary service inputs are locked before the optimization of wind and solar is done, which would then drive a change in the ancillary service requirement. To address this problem, the Company employed an iterative approach whereby estimated values were used and then recalibrated after the expansion plan was derived, then the data was adjusted and the model run again. This process was done during the numerous preliminary draft modeling runs completed leading up to preparation of the final Phase I modeling runs. From these preliminary draft modeling runs, a set of four "typical" ancillary service requirements curves were generated for use in this Phase I filing that are generally

[6] The Planning Reserve Margin and Resource Adequacy Study is provided as Attachment KDC-1 to the Direct Testimony of Company witness Mr. Kevin D. Carden. The Effective Load Carrying Capability Study is provided as Attachment KLS-2 to the Direct Testimony of Kent L. Scholl.

consistent with the expansion plans produced. These patterns were developed for ERP and CEP scenarios and SCC and $0/ton CO_2, resulting in four total curves. To be completely accurate, every single expansion plan run would need to be sequentially rerun until total convergence, but that is neither feasible nor required for this Phase I filing– the four patterns are reasonable to use as proxies for these cases. In Phase II of the ERP process, this iterative process will be utilized more thoroughly, to the extent practicable.

Q. HOW WAS THE FIRM CAPACITY OF EXISTING AND FUTURE GENERIC RESOURCES MODELED?

A. Company witness Mr. Scholl provides testimony regarding the ELCC study included in this filing. All existing resources were given ELCC values in accordance with the current loads and resources balance ("L&R"), and generic resources were modeled using the first two tranches of ELCC for wind, solar and storage. However, in the "No New Gas" sensitivity only, a third tranche of ELCC was added to better reflect the impact of greater additions of these resources in the absence on new thermal generics. In Phase II of the ERP process, all bids will be evaluated in accordance with the ELCC study. As in past Phase II competitive solicitations, initially all bids will be given "1st tranche" ELCC values, and either the overall portfolio ELCC will be adjusted in post-processing, or the model will be iterated using more refined ELCCs for the bids based on the optimization portfolio results that are ultimately presented in the Company's 120-Day Report.

Q. WERE WIND AND SOLAR INTEGRATION COSTS INCLUDED IN THE MODEL?

A. Yes, integration costs were added to existing and generic wind and solar in accordance with the integration study discussed in the Direct Testimony of Company witness Mr. Kent L. Scholl and the modeling assumptions summarized in Section 2.14 of Volume 2.[7]

Q. HOW WILL THE MODEL BE CONFIGURED TO EVALUATE BIDS TO FILL THE PLANNING PERIOD NEED?

A. Mr. Hill describes this in more detail in his Direct Testimony, and this is also discussed in Volume 2, but the primary differences in the model setup are issues that have been debated in past ERPs—mainly the "locked tail" issue and how to extend/replace bids that do not extend throughout the modeling period. For both of these issues, the Company is proposing minor modifications that incorporate positions taken by other parties in past ERPs with the objective of effectuating a fair evaluation of competing bids. For the locked tail, the Company is proposing that the generic expansion plan developed in the final Phase II model development, inclusive of all generic resources (thermal, wind, solar, storage), be locked in 2031 and beyond through the end of the Planning Period. This is consistent with Staff's "4B tail" sensitivity advocated for in the last ERP and that the Commission ordered to be included as a Phase II sensitivity in Proceeding No. 16A-0396E.[8] For extension of the bids, instead of the previous two approaches

[7] The Wind and Solar Integration Cost Study is provided as Attachment KLS-1 to the Direct Testimony of Company witness Mr. Kent L. Scholl.

[8] Decision No. C18-0191, at ¶¶ 76-77, Proceeding No. 16A-0396E.

used – i.e., the replacement method and annuity method – the Company is proposing a single unified approach where all bids are extended through the end of the Planning Period using an appropriate and relevant financial analysis methodology analysis. The details of this proposed methodology are contained in Volume 2. The Company is open to other approaches as well, but brings this proposal forward because it allows for a fair evaluation of the bids, in my opinion.

Q. DOES THE COMPANY PLAN TO UPDATE THE MODELING ASSUMPTIONS PRIOR TO PHASE II?

A. Yes. Consistent with past practice in prior ERPs, the Company will update its modeling inputs, assumptions, and methodologies consistent with the Commission's final Phase I Decision. Prior to issuing the all-source solicitation request for proposals ("RFPs"), the Company proposes to file a complete list of the EnCompass modeling inputs and assumptions consistent with its presentation in Section 2.14 of Volume 2, and will indicate which modeling inputs, assumptions, or methodologies have been updated for bid evaluation and selection purposes.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Consistent with the discussion in my Direct Testimony, I support the recommendation of Ms. Jackson that the Commission approve Public Service's Phase I 2021 ERP & CEP.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Jon T. Landrum

Jon Landrum is the manager of the analytics team for Resource Planning. The team maintains and uses the EnCompass planning model to perform resource planning studies and performs other ad hoc analyses in support of the company's strategic planning processes.

Mr. Landrum began his employment with Xcel Energy in May 2006 as the manager of the team that develops long range price forecasts for key commodities, including natural gas and market electricity. He later transitioned to a role leading the Asset Risk Analytics team that performs cost-benefit studies and infrastructure replacement analyses for the electric and gas distribution systems. He accepted his current position in Resource Planning in March 2013.

Prior to joining Xcel Energy, Mr. Landrum worked in multiple analytical and leadership roles in the Resource Planning, Commercial/Industrial DSM, and Marketing organizations at TECO Energy in Tampa, Florida. Jon has a B.S. in Electrical Engineering and a Masters in Business Administration, and was a Registered Professional Engineer in the state of Florida.

Jon has testified before the utility regulatory bodies of Colorado, Minnesota, and Florida in numerous dockets.