BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION OF THE CITY OF BOULDER, COLORADO FOR APPROVAL OF THE PROPOSED TRANSFER OF ASSETS FROM PUBLIC SERVICE COMPANY OF COLORADO TO THE CITY AND ASSOCIATED AUTHORIZATIONS AND RELIEF	**)**	**PROCEEDING NO. 15A-0589E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF JONATHAN B. KOEHN</u>

FILED IN SUPPORT OF THE SECOND SUPPLEMENTAL VERIFIED APPLICATION

OF THE CITY OF BOULDER

September 28, 2016

Colorado PUC E-Filings System

SUMMARY OF DIRECT TESTIMONY

Jonathan Koehn is the Regional Sustainability Coordinator for the City of Boulder ("Boulder" or the "City"). In his testimony, Mr. Koehn discusses the considerations that led to the development of Boulder's proposed plan for acquiring power and for simultaneously departing from the Public Service Company of Colorado ("PSCo") system in a gradual manner ("Gradual Departure Plan"). In presenting and explaining the bases for the Gradual Departure Plan, Mr. Koehn demonstrates that Boulder's plan for acquiring power is in the public's interest.

As Mr. Koehn testifies, the City's Gradual Departure Plan regarding its power supply is designed to help ensure reliability and the seamless transfer of responsibilities and services for customers, consistent with the City's priorities and objectives. Mr. Koehn discusses Boulder's available options for acquiring power and highlights the City's preferred alternative to fashion a transitional wholesale power supply arrangement with PSCo.

Given the importance of protecting PSCo's non-Boulder native load customers against unnecessary generation-related cost shifts, Mr. Koehn explains how Boulder's proposed Gradual Departure Plan is designed to minimize any burden on PSCo's customers and potentially benefit PSCo and its customers who will continue to be served by PSCo.

In presenting the Gradual Departure Plan, Mr. Koehn relies upon PSCo's resource projections which indicate that PSCo will not begin to experience capacity deficiencies until 2022 and that these deficiencies will grow from 284 MW in 2022 to a more significant 615 MW deficit in 2023. Mr. Koehn explains that, as contemplated, by coordinating Boulder's departure in a time frame consistent with PSCo's projected future resource needs, the City's Gradual Departure Plan not only helps ease the transition of Boulder's departure from the PSCo system, but also helps to

protect PSCo and its customers by promoting a least cost approach that avoids unnecessary investment in duplicative facilities.

In addition, Mr. Koehn describes the history in presenting to PSCo an April 16, 2015 request for power supply proposal ("RFP") in which the City invited PSCo to propose pricing options for various contract structures designed to allow Boulder to reduce its purchase of capacity and energy over time. Mr. Koehn also describes PSCo's May 18, 2015 RFP response, which provides Boulder with a conceptual framework under which Boulder would reduce its wholesale purchases from PSCo over time, and which may ultimately facilitate a requirements arrangement between PSCo and Boulder.

Finally, to provide context, Mr. Koehn discusses the terms of several of PSCo's existing power supply contracts with other wholesale customers in Colorado, each of which appears to be tailored to the entity involved. In doing so, Mr. Koehn also illustrates certain key features of PSCo's wholesale power supply contracts, including an early termination option, which may be an appropriate protection for the City and PSCo's non-Boulder native load customers, in a future wholesale power supply arrangement between Boulder and PSCo.

INDEX

SECTION **PAGE**

I. INTRODUCTION AND QUALIFICATIONS.....5

II. PURPOSE OF DIRECT TESTIMONY 7

III. BOULDER'S PLAN FOR POWER ACQUISITION 8

IV. BOULDER'S PROPOSED GRADUAL DEPARTURE PLAN 14

V. PSCO'S FULL AND PARTIAL REQUIREMENTS

CONTRACTS FOR WHOLESALE POWER.....27

VI. SUMMARY OF POSITION 30

LIST OF ATTACHMENTS

JBK-1	Statement of Qualifications for Jonathan B. Koehn
JBK-2	PSCo Electric Resource Plan 2014 Annual Report
JBK-3	Volume 1 of the 2016 Electric Resource Plan
JBK-4	Boulder RFP for Wholesale Power Supply dated April 16, 2015
JBK-5	Boulder Load Data: Discovery Response BLDR 2-3, BDLR 2-4, BLDR 3-1 and BLDR 3-2
JBK-6	Power Purchase Agreement between PSCo and Yampa Valley Electric Association, Inc.
JBK-7	PSCo Response to Boulder RFP dated May 18, 2015

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jonathan B. Koehn. My business address is 1101 Arapahoe, Boulder, Colorado, 80302.

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

A. I am employed by the City of Boulder ("Boulder" or "the City") as the Regional Sustainability Coordinator.

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

A. I am testifying on behalf of Boulder.

Q. HAVE YOU INCLUDED A DESCRIPTION OF YOUR QUALIFICATIONS, DUTIES AND RESPONSIBILITIES?

A. Yes. A description of my qualifications, duties, and responsibilities is included as **Attachment JBK-1**.

Q. AS THE REGIONAL SUSTAINABILITY COORDINATOR FOR BOULDER, WHAT ARE YOUR PRIMARY AREAS OF RESPONSIBILITY?

A. Broadly speaking, I advise Boulder regarding various energy initiatives that collectively support the City's efforts to achieve its Climate Action Plan ("CAP") emissions reduction targets. In this capacity, I develop and implement strategies designed to reduce carbon emissions in Boulder's built environment, energy procurement, distributed generation initiatives, and policy decisions. I was involved in the launch of Boulder's SmartGridCity™ platform and am involved in efforts to continually improve upon the deployment of that technology. I have participated in ongoing discussions related to Boulder's franchise agreement with PSCo and the decisions stemming from those negotiations.

In addition, I am a member of the City's Energy Future staff which is responsible for exploring the formation of the City's municipal electric utility and other strategies for achieving the City's carbon reduction goals.

Q. HAVE YOU PARTICIPATED PREVIOUSLY IN STATE OR FEDERAL ADMINISTRATIVE PROCEEDINGS ON BEHALF OF THE CITY OF BOULDER?

A. Yes. I have presented testimony on the City's behalf in proceedings before the Colorado Public Utilities Commission ("Commission" or "PUC") including Proceeding Nos. 09A-796E (PSCo's SmartGridCity™ Pricing Pilot); 09AL-299E (2009 Rate Case), 11A-833E (Revisions to Windsource Program); 11A-869E (2011 Electric Resource Plan ("ERP")); 12A-782E (Acquisition of the Brush 1, 3, and 4 Generation Facilities); and 12A-785E (Early Retirement of Arapahoe Unit 4). I have also been engaged, although without the submission of sponsored testimony, in Proceeding Nos. 10R-799EG (Smart Grid Data Privacy); 10R-674E (Solar Gardens); 11A-631EG (Electric and Natural Gas Demand-Side Management ("DSM") Plan for 2012 and 2013); 11A-418E (2012 Renewable Energy Standard Compliance Plan); 11I-704EG (Electric and Natural Gas Vehicles Investigatory Docket); 11M-426E (Solar Photovoltaic Financial Incentives); 12A-155E (Contract Terms for Customers within the City of Boulder); 12M-041E (Developing Scenarios Concerning the Future of Colorado's Electric Utility Service); 13A-0686EG (DSM Strategic Issues); 13A-0773EG (2014 Electric and Natural Gas DSM Plan); 13A-0836E (2014 Renewable Energy Standard Compliance Plan); 13M-102EG (Data Access & Privacy); 14A-0102E (Voluntary Service Offerings in the City of Boulder); 14A-0301E & 14A-0302E (Solar*Connect Program); 14M-0235E (Distributed Generation and Net Metering); and 14R-0394EG (Data Access and Privacy). In addition, I sponsored the City of Boulder's comments in response

to the United States Environmental Protection Agency's ("EPA") Clean Power Plan ("111(d)") Rulemaking process (Docket ID No. EPA-HQ-OAR-2013-0602, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units"; Proposed Rule, 79 Fed. Reg. 34829 (June 18, 2014)).

II. PURPOSE OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to present and provide support for (1) Boulder's proposed plan for acquiring power, and (2) simultaneously departing from the PSCo system in a gradual manner ("Gradual Departure Plan"). In presenting and explaining the basis for the Gradual Departure Plan, I demonstrate that Boulder's plan for acquiring power is in the public's interest. I will start with a brief background of Boulder's available options for acquiring power and will highlight the City's preferred alternative to fashion a transitional wholesale power supply arrangement with PSCo. I will also explain Boulder's proposed Gradual Departure Plan, designed to avoid any burden on PSCo's customers. My testimony will explain how Boulder's gradual departure from the PSCo system likely will benefit PSCo and its non-Boulder native load customers who will continue to be served by PSCo.

Consistent with the relief requested in the City's Application, I support Boulder's request that the Commission issue an order allowing Boulder to leave the PSCo system gradually, while simultaneously allowing PSCo's non-Boulder native load to absorb the PSCo-owned and contracted generation capacity, as it ceases to be used to serve Boulder. As contemplated, this simultaneous exchange will take place in a time frame consistent with PSCo's projected future resource needs. This approach not only protects PSCo and its

customers by promoting a least cost approach that avoids unnecessary investment in duplicative facilities or contracted generating capacity, and also helps ease the transition of Boulder's departure from the PSCo system.

III. BOULDER'S PLAN FOR POWER ACQUISITION

Q. PLEASE DESCRIBE THE CONSIDERATIONS THAT LED TO BOULDER'S PROPOSED PLAN FOR ACQUIRING POWER.

A. At such time as Boulder begins to provide electric service within the City, PSCo's existing customers within Boulder's municipal boundaries will become customers of the City's new electric utility. To provide electric service to its customers, the new electric utility would need to either (1) generate power or (2) engage in wholesale power purchases from the market. To ensure an effective and efficient transition, Boulder has developed what it believes to be the most viable approach for supplying its customers with power, and based on PSCo's current projections of its electric resource need, Boulder believes this approach will also benefit PSCo's remaining customers in a number of ways which I will describe in my testimony. I will also describe Boulder's Gradual Departure plan in greater detail throughout my testimony.

Q. IS BOULDER PLANNING TO GENERATE POWER IN ORDER TO SERVE ITS CUSTOMERS?

A. Boulder does not have any immediate plans to self-generate power beyond the hydroelectric facilities it currently operates. That said, Boulder envisions the expansion of distributed local generation in Boulder, such as customer-sited solar or community solar gardens. In addition, Boulder will continue to evaluate other generation options over time.

Q. IS BOULDER PLANNING TO CONDEMN GENERATION FACILITIES FROM PSCO AS PART OF ITS MUNICIPALIZATION PROCESS?

A. No. Boulder's plan to acquire the PSCo system in Boulder does not include plans to condemn any generating facilities from PSCo.

Q. ABSENT ANY PLANS TO GENERATE ADDITIONAL POWER, DOES BOULDER HAVE OPTIONS TO INSTEAD PURCHASE THE POWER IT NEEDS TO SERVE THE CITY'S CUSTOMERS?

A. Yes. Since announcing its intention to evaluate the feasibility of creating a municipal electric utility, Boulder has received numerous inquiries from third party independent power producers who are willing to enter into wholesale power supply contracts with the City. That said, Boulder's preferred power supply arrangement would be for Boulder to purchase power from PSCo for a fixed period of time in order to facilitate a gradual transition that benefits the City's and PSCo's respective customers. City witness Lloyd Reed, an expert in the field of wholesale power supply contracts, will describe in his testimony the City's options and process by which Boulder would procure wholesale power, and testifies that Boulder's Gradual Departure Plan is viable and consistent with industry standards.

Q. DOES THE CITY'S GRADUAL DEPARTURE PLAN INCLUDE CUSTOMERS LOCATED OUTSIDE THE CITY OF BOULDER?

A. No, it does not. As described in Boulder witness Heather Bailey's Direct Testimony, Boulder does not intend to serve PSCo customers located outside the City of Boulder.

Q. PLEASE EXPLAIN WHY BOULDER WOULD PREFER TO ENTER INTO A POWER SUPPLY ARRANGEMENT WITH PSCO.

A. Based on load and resource need projections from PSCo, Boulder believes that the new electric utility, can ably supply its customers with power, and simultaneously provide benefit and value to PSCo's remaining customers. Specifically, as Boulder proposes, the City would become a wholesale customer of PSCo, and enter into a wholesale power supply agreement for a designated period of time. Boulder could then gradually reduce its demand on the PSCo generation system over time. Under the Gradual Departure Plan, Boulder would leave the PSCo system incrementally over a stated time frame. Simultaneously PSCo's non-Boulder native load would absorb the PSCo-owned and contracted generation capacity, as it ceases to be used to serve Boulder. As contemplated, this approach would also allow PSCo to dedicate the generating resources it otherwise would have used to serve Boulder's load to meet demand elsewhere on the PSCo system in a manner that is coincident with PSCo's stated future resource need. Boulder sees this transition as a win-win approach for the City and for PSCo and its customers.

Q. HOW WOULD THIS APPROACH BENEFIT CUSTOMERS?

A. Boulder's preferred power purchase arrangement benefits PSCo's non-Boulder native load as well as Boulder customers, in several ways.

First, by gradually departing the PSCo generation system, Boulder will continue to absorb the PSCo-owned and contracted generation capacity that would otherwise be rendered surplus or redundant if Boulder were to depart immediately, as opposed to gradually. Second, such a gradual and transitional power supply arrangement benefits PSCo's non-Boulder native load by allowing PSCo to delay or defer any future need to build or acquire new power supply resources to serve its native load growth. In this way, Boulder's Gradual Departure Plan protects against the imposition of added and unnecessary

costs on PSCo's non-Boulder native load as a result of Boulder's decision to form a municipal utility. Third, this approach benefits customers of both PSCo's and Boulder's electric utility by ensuring that PSCo's capacity remains used, useful, and of value.

Effectively, the transitional power supply arrangement that Boulder proposes is designed to allay potential concerns that the City's formation of a new electric utility would somehow unfairly shift Boulder's share of the carrying costs for existing PSCo generation resources to other non-Boulder PSCo customers. Lastly, this allows for a smooth transition for all customers with minimal impact.

Q. LET'S FRAME THE DISCUSSION WITH SOME HISTORICAL CONTEXT. IS THIS THE FIRST TIME BOULDER HAS RAISED THE POSSIBILITY OF CONTINUING TO PURCHASE SOME OR ALL OF ITS ELECTRICITY NEEDS FROM PSCO ONCE IT MUNICIPALIZES?

A. No. Not only has this issue been previously raised with PSCo, but it also has been introduced to this Commission in previous proceedings. Specifically, I raised the issue in my Answer Testimony submitted on behalf of the City of Boulder in PSCo's 2011 ERP. As excerpted below, beginning on page 7, line 21 of my testimony in that proceeding, I discuss the possible scenarios for Boulder's power supply, as well as the option to develop a wholesale agreement with PSCo:

> **Q. RETURNING TO THE QUESTION RAISED BY THE COMPANY'S 2011 ELECTRIC RESOURCE PLAN, IF BOULDER FORMS A MUNICIPAL ELECTRIC UTILITY, WILL IT DISCONTINUE RECEIVING SERVICE FROM PSCO?**
>
> A. If Boulder does indeed choose to create a local electric utility, it is not likely that Boulder would immediately terminate receiving service from the Company altogether. In fact, there are several possible scenarios. First, Boulder could simply become a wholesale customer of the Company. Under

> that scenario, Boulder and PSCo may be able to develop a contract that would permit Boulder to purchase energy according to a fuel mix that would be chosen to best meet the needs of local customers. Second, Boulder could choose to receive part of its power from PSCo and another part from other independent power providers. Finally, Boulder may choose to purchase no service from PSCo, and take all of its service from other entities.

Boulder also raised this issue in its October 24, 2013 Comments on the 120-Day Report filed in the 2011 ERP proceeding. In Boulder's comments beginning on page 3, the City notes:

> Boulder has proposed previously and reiterates here its proposal that it work with Public Service and the Commission to release generation needed for Boulder as the Public Service load grows. Such a combined effort could defer the acquisition of generation required by Public Service's non-Boulder customers and save ratepayers the expense of that acquisition. As acknowledged by Public Service in the Application, there is a likelihood that Boulder's status as a retail customer of Public Service will change to that of a wholesale customer during the Resource Acquisition Period ("RAP").

Again on page 12:

Q. BOULDER WISHES TO WORK WITH THE COMMISSION AND PUBLIC SERVICE TO RELEASE BOULDER'S CAPACITY TO SERVE OTHER CUSTOMERS IN THE SERVICE TERRITORY.

A. In the final section of his Supplemental Answer Testimony in Phase 1 of this proceeding, Boulder witness Jonathan B. Koehn suggested that Public Service should not build or acquire new generation facilities to serve customers in Boulder, but rather should rely on short-term PPAs to fulfill its capacity needs during the proposed seven-year RAP.

> Mr. Koehn further suggested that, given the requirements of Boulder's home rule charter, it is likely that Boulder will want to acquire at least a portion of its power from an IPP that produces renewable energy. This would represent some level of reduced demand on the Public Service system, much as demand-side management programs reduce demand. A decrease in demand would reduce the need to acquire additional generation for the Public Service system, whether through building new generation facilities or contracting with an IPP for the delivery of power, thereby saving ratepayers the cost of acquiring that additional generation.

> Boulder has proposed previously that it work with the Commission and Public Service to release generation that serves Boulder as the Public Service load grows.

Q. HAS BOULDER HAD DISCUSSIONS WITH PSCO ABOUT BOULDER CONTINUING TO BE SERVED BY PSCO?

A. Yes. Since 2007, Boulder has engaged with PSCo in various discussions as it has considered its path forward toward forming a municipal electric utility. In order to facilitate a smooth transition, Boulder has had discussions with PSCo related to on-going power supply options.

To facilitate this dialogue, the City sent PSCo a Request for Proposal ("RFP") (**Attachment JBK-4**), on April 16, 2015, asking PSCo if it would sell power to a City electric utility for a limited time. Since that time, Boulder has continued to meet with PSCo with the objective of attempting to design a wholesale transitional power supply arrangement and discuss potential terms and conditions for such an agreement.

Q. PLEASE SUMMARIZE BOULDER'S OBJECTIVES IN APPROACHING PSCO WITH ITS RFP.

A. The City's primary interest in inviting PSCo's response to the RFP is in developing reasonable and economic power supply contractual arrangement that will balance the City's objectives of price stability and clean energy while ensuring that the City's plan is in the public's interest.

In the RFP, the City invited PSCo to propose pricing options for various contract structures that would allow Boulder to reduce its purchase of capacity and energy over time. This purchase would be scheduled to coincide with Boulder's existing self-generation (in the form of the City's hydro-electric assets and any distributed generation within the City) or anticipated purchases on the market in increasing blocks of power.

Q. HOW HAS PSCO RESPONDED THUS FAR TO BOULDER'S REQUEST FOR PROPOSALS?

A. On May 18, 2015, PSCo responded to Boulder's solicitation and expressed its willingness to sell Boulder electric energy for a limited period of time, should the City create its own electric utility (**Attachment JBK-7**). PSCo provided Boulder a general description of a conceptual framework, under which Boulder reduces its wholesale purchases from PSCo over time, designed to potentially facilitate a requirements arrangement between PSCo and Boulder. As stated previously, the City believes this approach is in the public's interest, and would help ensure reliability and the smoothest transfer of responsibilities and services for customers, consistent with the City's priorities.

PSCo's response to Boulder's RFP centered on a conceptual framework which it stated is intended to provide Boulder with high-level information regarding its power supply options and associated stranded cost mitigation. With respect to assessing power supply options, Boulder acknowledges the importance of avoiding unfairly shifting Boulder's share of the carrying costs for existing PSCo generation to its non-Boulder native load customers.

IV. BOULDER'S PROPOSED GRADUAL DEPARTURE PLAN

Q. YOU MENTIONED A POWER SUPPLY ARRANGEMENT WHEREBY BOULDER WOULD DEPART FROM PSCO'S SYSTEM GRADUALLY. PLEASE DESCRIBE HOW THAT PROCESS WOULD WORK.

A. Boulder proposes to depart from PSCo's native load—and provide electric power and services to Boulder's customers—in a manner coincident with PSCo's projected resource need, up to the level of Boulder's own demand. In this way, Boulder would gradually

introduce into its power supply mix capacity and energy supplied by resources other than those owned by PSCo that begins to address Boulder's goal of reducing carbon emissions 80% below 2005 levels by 2050.

Based on PSCo's forecasted resource need, Boulder wishes to transition its power supply at a pace that protects against the need for PSCo to add new owned or contracted generating capacity to its system to serve Boulder's load. In addition, Boulder designed its plan so that the PSCo-owned and contracted generation resources can be gradually redirected to provide service to PSCo's non-Boulder native load, as those generating resource cease to be used to serve Boulder. This redirection can be done in a manner that protects PSCo's native load customers against the incurrence of unreasonable costs.

Q. HOW DOES BOULDER ENVISION THE POWER SUPPLY AGREEMENT WOULD BE STRUCTURED?

A. A power supply agreement with PSCo could be structured in several different ways, which resemble the respective structures of wholesale power supply arrangements that PSCo has with other wholesale customers, as described later in my testimony. Boulder is flexible in this regard.

That said, Boulder proposes that the City would purchase wholesale power from PSCo as a full requirements customer pursuant to PSCo's wholesale formula rate currently on file with Federal Energy Regulatory Commission ("FERC"). As discussed in more detail later in my testimony, PSCo currently serves six wholesale requirements customers under this formula rate. Boulder anticipates that any requirements agreement with PSCo would utilize PSCo's wholesale formula rates.

What this means is that the City would remain a requirements customer for a specified period under a Power Purchase Agreement ("PPA"), following which the City would gradually procure its own firm resources in accord with a pre-defined schedule spanning the term of the PPA. The full requirements phase of such an agreement would likely have the following elements:

1. Supply mix used to serve Boulder would be generally the same resource mix as the rest of the PSCo service territory (in effect, a "slice" of the PSCo system, which is consistent with the pricing under PSCo's wholesale formula rate);
2. Relatively short-term (e.g., five years or less) for full requirements, then transitioning through decreasing blocks of PSCo generation as PSCo's non-Boulder native load grows, and as Boulder expands its non-PSCo resource portfolio or reduces its overall load;
3. Proportionate to net dependable capacity need; and
4. Adaptable to the development of additional distributed, primarily renewable, generation within Boulder's municipal limits, without disruption to the ongoing power supply transition.

Q. YOU SAY BOULDER WOULD GRADUALLY DEPART THE PSCO SYSTEM BASED ON RESOURCE NEED. HOW DOES THE CITY KNOW PSCO'S FORECASTED RESOURCE NEEDS?

A. For the City's 2015 Application, the City relied on information provided in PSCo's 2014 Annual Progress Report for its 2011 ERP filed on October 31, 2014 (**Attachment JBK-2**)

("2014 ERP Report")[1]. According to that 2014 ERP Report, PSCo did not anticipate needing any additional capacity to meet its projected resource need until 2020.

Table 1 below is excerpted from page 4 of PSCo's 2014 ERP Report (**Attachment JBK-2**) and shows PSCo's previous resource position relative to its demand forecast for the subsequent 10-year period.

TABLE 1

PSCo Loads & Resources Balance Summer September 2014 Demand Forecast										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Summer Net Dependable Capacity	7,495	7,533	7,507	7,438	7,300	7,312	7,322	7,076	6,802	6,694
Peak Load	6,595	6,653	6,725	6,784	6,841	6,906	6,974	7,047	7,123	7,201
Dispatchable Demand Reduction	528	537	555	575	598	623	623	623	623	623
Obligation Load	6,067	6,116	6,170	6,209	6,243	6,283	6,351	6,424	6,500	6,578
Reserve Margin (16.3%)	989	997	1,006	1,012	1,018	1,024	1,035	1,047	1,059	1,072
IREA and HCEA Reserves	40	40	40	40	40	40	40	40	40	40
Total Required Margin	1,029	1,037	1,046	1,052	1,058	1,064	1,075	1,087	1,099	1,112
Resource Need	-	-	-	-	**0**	**34**	**104**	**435**	**798**	**996**

Q. HASN'T PSCO RELEASED AN UPDATED DEMAND FORECAST AS PART OF ITS RECENTLY FILED 2016 ELECTRIC RESOURCE PLAN?

A. Yes. On May 27, 2016, PSCo submitted its most recent ERP ("2016 ERP"). Phase I of the ERP includes information regarding the utility's electric system, an assessment of the need

[1] In accordance with Commission Rule 3618(a), the annual progress reports are intended to "…inform the Commission of the utility's efforts under the approved plan and the emerging resource needs and potential utility proposals that may be part of the utility's next electric resource plan filing." These annual progress reports are also required to contain the following data:

(1) An updated annual electric demand and energy forecast;
(2) An updated evaluation of existing generation resources;
(3) An updated evaluation of planning reserve margins and contingency plans;
(4) An updated assessment of need for additional resources; and
(5) An updated report of the utility's plan to meet the resource need and the resources the utility has acquired to date in implementation of the plan.

for additional resources, and the utility's plan to acquire those resources. Through the Phase I proceedings, the Commission establishes the need for new resources and the general methodology and assumptions the utility is to use in evaluating generation resources during the Phase II acquisition phase of the plan. In other words, the 2016 ERP provides the framework for how PSCo assesses the need for future electric supply resources over the specified 8-year Resource Acquisition Plan (RAP) from May 2016 through May 2024, as well as PSCo's plan for acquiring those resources.

Volume 1 of PSCo's 2016 ERP (**Attachment JBK-3**) contains an updated projection of resource needs along with PSCo's plan for meeting those needs. In its filing, PSCo has identified additional generation resources to be procured in its next all-source solicitation. Table 2 below is taken from page 1-32 of PSCo's 2016 ERP Volume 1, and represents an updated projected resource need.

Table 2

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

Embedded within the Existing & Planned Generation values in Table 2 are the planned generation additions reflected in PSCo's 2017 RE Plan (Proceeding No. 16A-0139E), PSCo's proposed Solar*Connect Program (Proceeding No. 16A-0055E), and PSCo's proposed Rush Creek Wind Project (Proceeding No. 16A-0117E). Consistent with

prior practice, PSCo has also projected continued annual acquisitions of Retail distributed generation (DG) at the same levels as proposed in the 2017 Renewable Energy Plan throughout the RAP. When determining the resource needs to be filled through the Phase II acquisition process of the ERP, PSCo will update these estimates in accordance with the Commission decisions in these proceedings.

Q. WHY DO YOU INCLUDE DISCUSSION OF THE 2014 ERP ANNUAL REPORT WHEN THERE IS MORE RECENT INFORMATION AVAILABLE IN THE 2016 ERP?

A. The Loads and Resources ("L&R") from the 2014 ERP Report (Table 1) is included as a reference point. Although the more recent L&R projections shown in Phase 1 of PSCo's 2016 ERP (Table 2) are indicative of the more recent forecasted resource needs that PSCo is currently planning around, the projections are based on generation assets that are not yet approved by the Commission. What this shows is that PSCo's forecasts are not definitive, and the City's Gradual Departure Plan acknowledges and anticipates a flexible approach in being equipped to respond to the projections as they become more refined.

Q. SHOULDN'T ANY SCHEDULE FOR BOULDER'S DEPARTURE BE BASED ON PSCO'S CAPACITY NEEDS AS ILLUSTRATED IN TABLE 2?

A. Not necessarily. In PSCo's more recent L & R Table (Table 2), PSCo experiences a capacity need in 2022. This is due in large part, to PSCo's proposed generation additions reflected in the 2017 RE Plan (Proceeding No. 16A-0139E), Solar*Connect Program (Proceeding No. 16A-0055E), and Rush Creek Wind Project (Proceeding No. 16A-0117E). In the event that some of these proposed resources are not approved, or if actual participation in customer programs is lower than anticipated, the amount of generation resources ultimately acquired

could be lower than anticipated resulting in an increase in PSCo's resource need from that depicted in Table 2.

Q. ARE THERE OTHER CONTINGENCIES THAT MIGHT CHANGE PSCO'S RESOURCE NEED?

A. Yes. PSCo acknowledges the ongoing uncertainty in resource need assessment. In its 2016 ERP, PSCo identifies additional uncertainties that could influence both the generation and load sides of the L&R balance in Table 2, and will either increase or decrease the resource needs that are filled in the Phase II ERP process. Table 3 below, is taken from page 1-34 of Volume 1 of the 2016 ERP (**Attachment JBK-3**), and quantifies the approximate impact on resource need from generation or load uncertainties in megawatts.

Table 3

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

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

In addition to all of the uncertainty factors affecting load and generation levels listed above, it is also important to note that PSCo's needs assessment could easily adapt to include

the potential of Boulder's gradual exit from the PSCo system. Therefore, Boulder's proposed gradual transition away from being served by PSCo's generation resources allows PSCo the ability, in advance of Phase II of the ERP, to plan for its non-Boulder native load to absorb the PSCo-owned and contracted generation capacity, as it ceases to be used to serve Boulder.

Q. DOES PSCO'S FIRM OBLIGATION LOAD VALUES SHOWN IN TABLE 2 CURRENTLY INCLUDE BOULDER'S ANTICIPATED FIRM LOAD?

A. Yes. On page 1-33 of Volume 1 of the 2016 ERP (**Attachment JBK-3**) PSCo clearly states that the firm obligation load:

> *…includes a forecast of the City of Boulder's entire firm load obligation over the 8-year RAP. Notwithstanding Boulder's stated intentions to form a municipal utility system, [PSCo] has a continuing legal obligation to plan its system to serve Boulder's load.*

Q. IF PSCO'S LOAD REQUIREMENTS CHANGE FROM WHAT HAS BEEN FORECASTED, DOES THAT CHANGE THE TRAJECTORY OF BOULDER'S DEPARTURE?

A. Boulder recognizes that PSCo's projections will be refined over time. Therefore, to make sure the transition is as accurate as possible, Boulder proposes that PSCo provide the City with an updated forecasted resource need for each calendar year thereby providing a three-year advance notice for resource planning purposes. At the same time, the City will attempt to coordinate with PSCo, provided PSCo's cooperation, to develop an accurate forecast of its peak demands (including its planned reserve margin) each year. Based on those forecasts, the City and PSCo will plan for the City to secure resources from a source other than a PPA with PSCo in the amount of PSCo's forecasted resource need, if any, up to the

level of Boulder's forecast peak demands. Boulder further proposes that the process repeat and new forecasts be provided each year until the PSCo forecasted resource need is greater than the City's peak demand. Once that event occurs, Boulder will be free to acquire its generation needs as it deems appropriate.

Under this approach, the timing of Boulder's departure will coincide, to the extent possible, with PSCo's actual resource needs as such needs are forecasted over time. Thus, as forecasts are updated, Boulder's departure could come sooner or later than currently anticipated. In other words, potential changes in PSCo's resource need projections would not invalidate the City's Gradual Departure Plan – they only would impact the timing of when certain events occur.

Finally, the approach discussed above is certainly not the only option available. In particular, the City is amenable to an arrangement for the exchange of forecasts with PSCo through the ERP or some other alternatively designated forum or on a different schedule. The critical issue for the City is that whatever process is approved, both PSCo and City will know how much capacity each utility needs to acquire to serve their respective customers' resource needs with sufficient lead time for both utilities to acquire any needed capacity, at costs and under terms that are reasonable.

Q. IF A GRADUAL DEPARTURE WILL BE TIED DIRECTLY TO BOULDER'S DEMAND, CAN YOU PLEASE PROVIDE BOULDER'S ANTICIPATED DEMAND?

A. The City anticipates an initial peak load of 257 MW by 2018, which includes a 16.3% reserve margin. While there is no regulated interconnection-wide reserve margin requirement, the appropriateness of a 16.3% planning reserve target for the PSCo system

was established through a collaborative study effort among the Commission Staff, the Office of Consumer Counsel, and PSCo.[2] Therefore, a similar reserve margin for a Boulder utility seems reasonable.

Table 4 below illustrates the City's current best estimate of Boulder's total forecasted annual demand and energy growth requirements between 2018 and 2022. Boulder's estimated growth rate is 0.56% in coincident peak demand compared to a Colorado system average of 0.83%. This may be due to Boulder's relatively flat load profile and local investments in energy efficiency and distributed generation which are supported in large part by Boulder's CAP Tax.

TABLE 4: Boulder's Forecasted Energy and Peak Demand

Year	Energy (MWh)	Peak Demand (MW)
2018	1,518,124	257
2019	1,528,687	258
2020	1,542,440	259
2021	1,547,969	261
2022	1,557,645	262

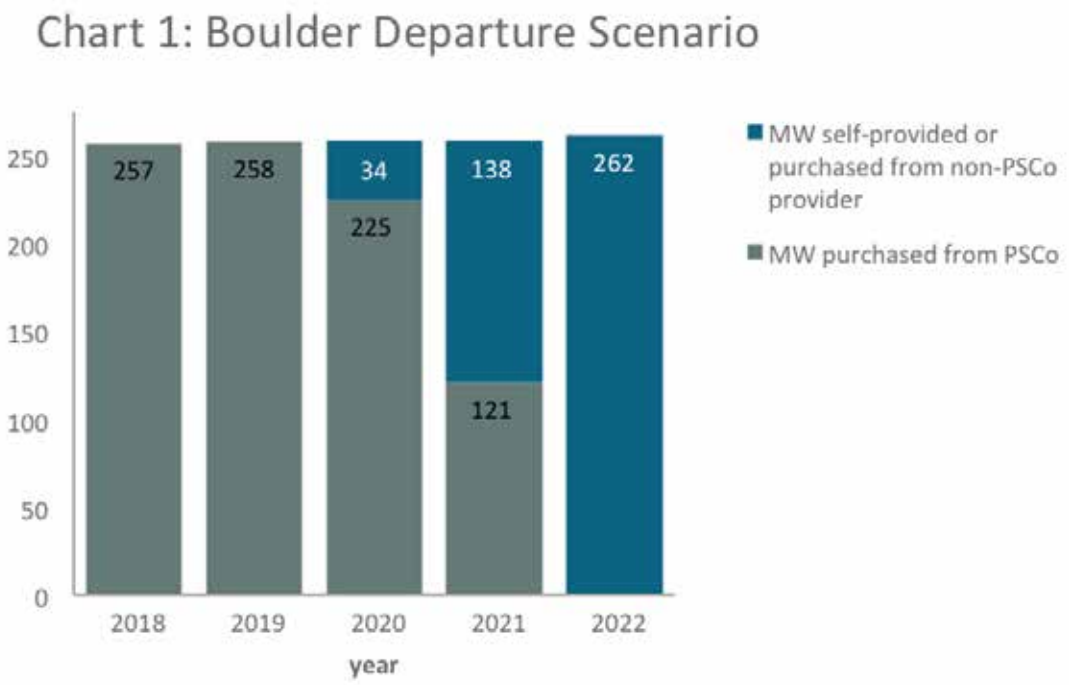
To be clear, Boulder does not have access to load information concerning Boulder customers. The annual forecast in Table 4 above was developed using data received in August 2012 and provided by PSCo in response to Discovery Requests BLDR 2-3, BLDR 2-4, BLDR 3-1 and BLDR 3-2 in the 2011 ERP (monthly adjusted to annual), a copy of which is provided as **Attachment JBK-5**. I would note that in Boulder's April 16, 2015 RFP, the City asked PSCo to provide any updated historic or forecasted load information

[2] A detailed discussion of the Planning Reserve Margin is included in Section 2.6 of PSCo's 2016 ERP, Volume 2. A loss of load probability study is provided for reference in Section 2.13 of Volume 2.

for Boulder. Upon PSCo's provision to Boulder of more accurate system use and load projections, the estimates provided in Table 4 would be adjusted as necessary.

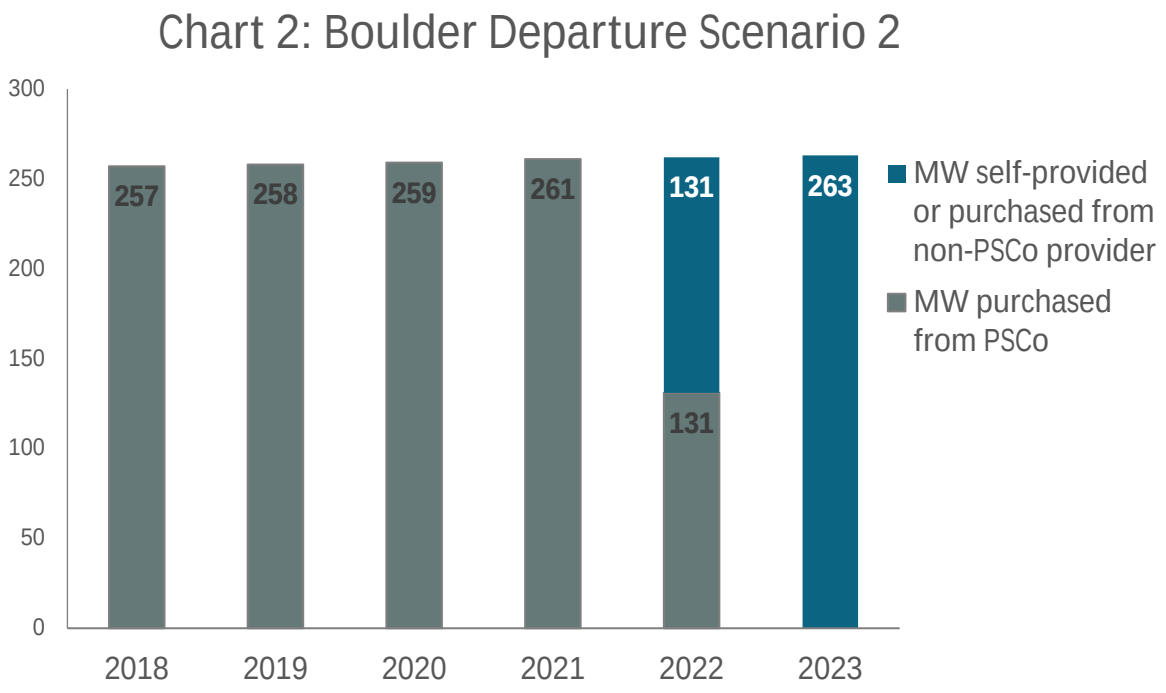
Q. WHAT IMPACT DOES BOULDER'S ANTICIPATED DEMAND HAVE ON THE CITY'S TIMELINE FOR DEPARTURE?

A. Based on PSCo's approved resource requirements established in the 2011 ERP, Boulder could begin its gradual departure from the PSCo system beginning in 2020, with a full departure determined by PSCo's future resource requirement as shown in Chart 1 below:



As an alternative, Boulder could agree to a departure schedule commensurate with PSCo's revised resource need should the generation additions identified in PSCo's 2016 ERP be approved. Based on PSCo's shown need of 284 MW in 2022, that scenario could result in all of Boulder's load (~262MW) shifting from PSCo in 2022, or half in 2022 and the remaining load in 2023 as illustrated in Chart 2 below:

1



Q. DO THESE DEPARTURE SCENARIOS REPRESENT THE ONLY TWO OPTIONS THE CITY WOULD CONSIDER?

A. Absolutely not. It's important to emphasize that the City's planned trajectory is not tied to PSCo's needs exceeding Boulder's peak. Instead, the trajectory is tied to the decreasing energy supply that Boulder takes from PSCo, coincident with how PSCo's resource needs increase elsewhere on PSCo's system. This could result in a departure schedule that is implemented in equal increments over an agreed upon term, or any other mutually agreeable schedule.

V. PSCO'S FULL AND PARTIAL REQUIREMENTS CONTRACTS FOR WHOLESALE POWER

Q. YOU'VE DESCRIBED THAT BOULDER WOULD BECOME A WHOLESALE CUSTOMER OF PSCO. DOES PSCO HAVE SIMILAR POWER SUPPLY CONTRACTS WITH OTHER CUSTOMERS IN COLORADO?

A. Yes. From what I understand, PSCo has requirements contracts with the following six entities (and possibly others): the City of Burlington; the Town of Center; Grand Valley Rural Power Lines, Inc.; Holy Cross Electric Association, Inc. ("Holy Cross"); Intermountain Rural Electric Association ("IREA"); and Yampa Valley Electric Association, Inc. ("YVEA").

Q. WHAT PERCENTAGE OF PSCO'S TOTAL SALES DO THOSE CONTRACTS COLLECTIVELY REPRESENT?

A. According to Xcel Energy's Form 10-K filed with the U.S. Securities and Exchange Commission, for the fiscal year ending December 31, 2015, PSCo's service of wholesale customers comprised approximately 11 percent of PSCo's total kWh sold in Colorado in 2015.[3]

Q. PLEASE DESCRIBE SOME OF THOSE CONTRACTS AND CUSTOMERS.

A. While, unlike Boulder witness Lloyd Reed, I am not an expert on power contracts, it is my understanding that PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy, and energy-related products. PSCo has established FERC-approved tariff rates for wholesale requirements service (*see Public Serv.*

[3] Xcel Energy Form 10-K: Part 1, page 6

Co. of Colorado, 135 FERC ¶ 61,012 (2011)). PSCo currently serves its wholesale requirements customers under a wholesale formula rate, pursuant to which PSCo recovers its costs from wholesale requirements customers using a formula rate that has a forward-looking test year that is later trued up against actual costs and demands. Boulder anticipates that any requirements agreement with PSCo would be based on the same formula rates.

In terms of the individual agreements, it appears that each power supply contract tends to be tailored to the entity involved. For example, Holy Cross is engaged in the generation, transmission and distribution of electric power and energy purchases. Holy Cross takes Full Requirements service from PSCo with the option to convert to Partial Requirements service. Within this arrangement, Holy Cross may purchase energy from other suppliers in lieu of Full Requirements Service or Partial Requirements Service energy purchases from PSCo. Holy Cross receives a Western Preference Power capacity and energy allocation from Western's Salt Lake City Integrated Projects ("SLC/IP"), and PSCo allows Holy Cross to utilize Preference Power resources allocated to it in conjunction with either Full Requirements or Partial Requirements Service wholesale power purchased from PSCo.

The City of Burlington, Colorado purchases its power and energy requirements from two wholesale power suppliers: the Western Area Power Administration ("WAPA") and PSCo. Burlington's Electric Department also owns and maintains local generation, which is used to supply back-up service during emergency situations, including scheduled and unscheduled transmission line outages and scheduled substation outages.

Therefore, as I understand it, PSCo already has requirements contracts that appear to be customized. The type of arrangement Boulder is proposing is generally consistent

with PSCo's existing agreements. Although Boulder's proposal may be somewhat unusual in terms of the phasing aspect, as City witness Mr. Reed confirms, the structure of a tailored agreement is quite commonplace.

Q. YOU STATE THAT BOULDER'S PROPOSAL IS SOMEWHAT UNUSUAL IN TERMS OF THE PHASING ASPECT. DO ANY OF PSCO'S OTHER WHOLESALE CONTRACTS OFFER A SIMILAR STRUCTURE?

A. Yes. As an example, PSCo's PPA with YVEA (**Attachment JBK-6**), contains an early termination option in which YVEA may reduce its Full Requirements Service purchases from PSCo to Partial Requirements Service. The level of notice required by YVEA is a function of the proposed level of reduction of total load supplied by PSCo. Exhibit C of the Wholesale Power Purchase Agreement shown in Insert JBK-1 below identifies the terms of YVEA's "Early Termination Option":

Insert JBK-1

EARLY TERMINATION OPTION

Customer may convert any point(s) of delivery served under this Agreement to Partial Requirements Service, with such service to commence no earlier than January 1, 2025. If Customer elects to convert to Partial Requirements Service, it shall give Public Service notice of the Point(s) of Delivery which will be converted to Partial Requirements Service, and the amount by which it proposes to reduce its Full Requirements Service purchases from Public Service. The notice required shall be a function of the proposed level of reduction of total load supplied by Public Service in accordance with the following schedule:

Minimum Notice	Percent of Maximum Load Reduction
12 Months	20%
24 Months	40%
36 Months	60%
48 Months	80%
60 Months	100%

If Customer elects to convert to Partial Requirements Service, Public Service shall make available to Customer a Partial Requirements Service rate. If the Parties cannot agree on the appropriate Partial Requirements Service rate, Public Service shall make the appropriate filing with the FERC seeking implementation of a Partial Requirements Service rate, and Customer shall have the right to contest such filing.

Boulder's proposal is similar to YVEA's in terms of the ability to gradually depart from the PSCo system; with the only distinguishable difference being that the percentage of maximum load reduction is based on PSCo's resource need.

Taken together, these wholesale power arrangements demonstrate that there are options to tailor an agreement to PSCo's and the City's respective needs.

VI. SUMMARY OF POSITION

Q. COULD YOU PLEASE BRIEFLY SUMMARIZE YOUR DIRECT TESTIMONY?

A. Boulder's proposed plan for acquiring power and for simultaneously departing from the PSCo system consistent with the Gradual Departure Plan is in the public's interest.

The City's Gradual Departure Plan regarding its power supply is designed to help ensure reliability and the seamless transfer of responsibilities and services for customers. Boulder acknowledges the importance of protecting PSCo's non-Boulder native load customers against unnecessary generation-related cost shifts, and designed its Gradual Departure Plan to minimize any burden on PSCo's customers and potentially benefit PSCo and its customers who will continue to be served by PSCo.

Boulder's proposal is based upon PSCo's resource projections, and by coordinating Boulder's departure in a time frame consistent with PSCo's projected future resource needs, the City's Gradual Departure Plan not only helps ease the transition of Boulder's departure from the PSCo system, but also helps to protect PSCo and its customers by promoting a least cost approach that avoids unnecessary investment in duplicative facilities.

In providing PSCo with the April 16, 2015 RFP, the City invited PSCo to propose pricing options for various contract structures designed to allow Boulder to reduce its purchase of capacity and energy over time. Given the apparently tailored terms of several of PSCo's existing power supply contracts with other wholesale customers in Colorado, the City seeks to enter into a transitional wholesale power agreement with PSCo. In this regard, an Early Termination Option much like that provided to YVEA, may be an appropriate protection for the City and PSCo's non-Boulder native load customers, in a wholesale power supply arrangement between Boulder and PSCo.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, thank you.

JONATHAN B. KOEHN
STATEMENT OF QUALIFICATIONS

Jonathan Koehn is the City of Boulder's Regional Sustainability Coordinator, in the City's Community Planning and Sustainability Department. He is also working jointly in the City's Department of Energy Strategy and Electric Utility Development where he works to implement the city's sustainability agenda, specifically in relation to climate action and waste reduction, but more broadly across the complete spectrum of the city's sustainability goals.

He began his tenure in Boulder as the Environmental Manager for the city of Boulder in 2006, with over 13 years' experience working with state, regional and local governments and their constituencies domestically and internationally to develop strategic and tactical solutions to energy, economic and climate challenges. In recent months, he has also been responsible for a number of aspects of the city's municipalization exploration project including analyses and research on potential resource portfolio issues along with specific policy recommendations related to the energy future efforts.

Koehn has submitted testimony to the Colorado Public Utilities Commission on behalf of the City of Boulder including SmartGridCity, demand-side initiatives, Windsource and SolarRewards. He has worked in the nonprofit, academic, and government sectors and holds a Masters Degree in Environmental Science and Biology from the University of Northern Arizona, and a Bachelors in Marine Sciences from the University of Florida.

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Annual Progress Report
2011 Electric Resource Plan

(CPUC Proceeding No. 11A-869E)

October 31, 2014

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Table 1 Demand and Energy Forecast

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Annual Energy Sales (GWh)	31,190	31,450	31,780	31,990	32,100	32,400	32,630	32,940	33,270	33,650
Summer Peak Demand (MW)	6,595	6,653	6,725	6,784	6,841	6,906	6,974	7,047	7,123	7,201

2. Existing Generation Resources

Table 2 below shows that the Company's Total Summer Net Dependable Capacity ("NDC") is projected to decrease by ~800 MW over the time period from 2015 to 2024. Company-owned generation results in a net increase of 170 MW over the time period. NDC from the new 569 MW Cherokee combined-cycle unit (Units 5, 6, 7) is offset by the retirement of ~330 MW of coal-fired generation and 59 MW of gas-fired generation. Approximately 320 MW of incremental NDC from new purchased generation is offset by the expiration of ~1,080 MW from existing contracts.

Table 2 Summer Net Dependable Capacity

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Company-Owned Generation										
Summer Net Dependable Capacity	4,958	4,958	4,958	4,958	4,958	4,958	4,958	4,958	4,958	4,958
Additions										
Cherokee 5, 6, 7		569	569	569	569	569	569	569	569	569
Total Additions	-	569	569	569	569	569	569	569	569	569
Retirements										
Cherokee 3		(152)	(152)	(152)	(152)	(152)	(152)	(152)	(152)	(152)
Valmont 5				(184)	(184)	(184)	(184)	(184)	(184)	(184)
Zuni 2		(59)	(59)	(59)	(59)	(59)	(59)	(59)	(59)	(59)
Ponnequin (Wind)		(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Total Retirements		(214)	(214)	(398)	(398)	(398)	(398)	(398)	(398)	(398)
Summer Net Dependable Capacity	4,958	5,312	5,312	5,128	5,128	5,128	5,128	5,128	5,128	5,128
Purchased Generation										
Summer Net Dependable Capacity	2,537	2,537	2,537	2,536	2,536	2,536	2,536	2,535	2,535	2,535
Additions										
Brush 1/3				78	78	78	78	78	78	78
Comanche (Solar)			66	66	66	66	65	65	65	64
Hooper (Solar)		28	28	28	27	27	27	27	27	27
Golden West (Wind)		31	31	31	31	31	31	31	31	31
Solar Gardens		4	4	4	3	3	3	3	3	3
Net-Metered Generation		16	33	46	58	71	83	95	108	120
Total Additions	-	78	162	252	264	276	288	300	312	324
Contract Terminations										
Basin Electric Contracts		(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)	(170)
Tri-State Contracts		(24)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)
Pacificorp Contract									(150)	(150)
Brush 1/3				(75)	(75)	(75)	(75)	(75)	(75)	(75)
Brush 4D									(133)	(133)
Arapahoe 5, 6, 7										(119)
Tri-State Shafer					(129)	(129)	(129)	(129)	(129)	(129)
Manchief								(258)	(258)	(258)
Tri-State Limon/Brighton		(198)	(198)	(198)	(198)	(198)	(198)	(198)	(198)	(198)
Ridge Crest (Wind)			(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Colorado Green (Wind)					(20)	(20)	(20)	(20)	(20)	(20)
Small Renewable		(2)	(8.9)	(11)	(11)	(11)	(12)	(12)	(15)	(15)
Total Retirements	-	(394)	(503)	(580)	(729)	(729)	(731)	(989)	(1,275)	(1,394)
Summer Net Dependable Capacity	2,537	2,221	2,195	2,208	2,071	2,083	2,093	1,847	1,572	1,465
SPS Diversity Exchange	-	-	-	101	101	101	101	101	101	101
Total Summer Net Dependable Capacity	**7,495**	**7,533**	**7,507**	**7,438**	**7,300**	**7,312**	**7,322**	**7,076**	**6,802**	**6,694**

3. Planning Reserve Margins and Contingency Plans

The Company conducted a planning reserve margin study pursuant to Commission Decision No. C08-0929. That study determined a 16.3% planning reserve margin applied to the 50th percentile peak demand forecast was needed to maintain an acceptable level of reliability.[3] The Commission approved the use of the 16.3% planning reserve margin for the Company's 2011 ERP.

Based on its projection of resources in excess of peak demand forecasts plus 16.3% planning reserve margins through 2018 shown in Table 3 below, the Company does not contemplate the need to implement any contingency plans for additional resources in advance of the 2015 ERP filing. An updated projection of resource need along with the Company's plan for meeting those needs will be provided as part of the Company's 2015 ERP that will be filed with the Commission by October 31, 2015.

4. Need for Additional Resources

Table 3 shows the Company's projected resource position relative to its demand forecast for the next 10-year period. The first projected need for incremental resources is 34 MW in 2020 growing to ~1,000 MW by 2024. Expiring purchased power agreements ("PPAs") totaling 664 MW of net dependable capacity after 2019 represent 67% of the incremental resource need in 2024; forecasted annual growth in net peak demand represents the balance of the incremental resource need.

Table 3 Loads and Resources Table[4]

PSCo Loads & Resources Balance Summer September 2014 Demand Forecast										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Summer Net Dependable Capacity	7,495	7,533	7,507	7,438	7,300	7,312	7,322	7,076	6,802	6,694
Peak Load	6,595	6,653	6,725	6,784	6,841	6,906	6,974	7,047	7,123	7,201
Dispatchable Demand Reduction	528	537	555	575	598	623	623	623	623	623
Obligation Load	6,067	6,116	6,170	6,209	6,243	6,283	6,351	6,424	6,500	6,578
Reserve Margin (16.3%)	989	997	1,006	1,012	1,018	1,024	1,035	1,047	1,059	1,072
IREA and HCEA Reserves	40	40	40	40	40	40	40	40	40	40
Total Required Margin	1,029	1,037	1,046	1,052	1,058	1,064	1,075	1,087	1,099	1,112
Resource Need	-	-	-	-	**0**	**34**	**104**	**435**	**798**	**996**

5. Acquisition of Generation Resources from 2013 All-Source Solicitation

In Decision No. C13-1566, the Commission approved the Company's preferred portfolio of incremental generation resources identified in the 2013 All-Source Solicitation. These resources included:

[3] Reliability set at a 1 day in 10 year loss of load probability.

[4] Goals filed in the Company's 2015/2016 DSM Plan (Exhibit WTC-1 Docket No. 14A-1057EG) for Dispatchable Demand Reduction are 485 MW in 2015 and 496 MW in 2016. A description of these Demand Response goals are included on pages 294-295 of exhibit WTC-1.

- 18-year PPA for the existing 242 MW Fountain Valley gas-fired facility,
  - The Company successfully executed a PPA for the Fountain Valley facility and purchases under the contract began on January 1, 2014.
- 8-year PPA for the existing 78 MW Brush 1/3 gas-fired facility,
  - The Company successfully executed a PPA for the Brush 1/3 facility and purchases under the contract will begin on May 1, 2017, following the termination of the existing PPA.
- 25-year PPA for the new 200 MW Limon III wind facility,
  - The Company successfully executed a PPA for the Limon III facility and purchases under the contract began on October 2, 2014.
- 25-year PPA for the new 250 MW Golden West wind facility,
  - The Company successfully executed a PPA for the Golden West facility and purchases under the contract are expected to begin in the 4th quarter 2015.
- 25-year PPA for the new 120 MW Comanche PV Solar facility,
  - The Company successfully executed a PPA for the Comanche Solar facility and purchases under the contract are expected to begin in the 2nd quarter of 2016.
- 20-year PPA for the new 50 MW Hooper PV Solar facility,
  - The Company successfully executed a PPA for the Hooper Solar facility and purchases under the contract are expected to begin in the 4th quarter of 2016.[5]
- Continued operation of the Company's 352 MW Cherokee Unit 4 on natural gas beginning no later than January 1, 2018, and
- Early retirement of the Company's 109 MW Arapahoe Unit 4.
  - The Company's Arapahoe Units 3 and 4 are retired.

Discussion of Emerging Issues that Could Impact the 2015 ERP Filing

EPA's Proposed Clean Power Plan

On June 2, 2014 the Environmental Protection Agency ("EPA") issued its proposed Clean Power Plan to reduce carbon dioxide emissions from existing electricity generating plants. The plan as proposed would require the State of Colorado to reduce its carbon dioxide emissions from a rate of 1,714 lbs/MWh in 2012 to a rate of 1,108 lbs/MWh by 2030.[6] Due to initiatives that reduce emissions, such as the implementation of the Clean Air-Clean Jobs Act, ongoing renewable additions, and demand-side management programs, the emissions associated with the energy

[5] The Company has executed an additional PPA for an advanced in-service date for the Hooper Solar facility. Generation from the facility under this additional PPA is intended for use in the Company's proposed Solar*Connect program. Purchases under this additional PPA terminate at the start of the PPA executed pursuant to Decision No. C13-1566.

[6] Although Colorado's 2012 existing fossil generation resource rate (from those resources covered under the Clean Power Plan) was 1,959 lbs/MWh, this rate does not include existing renewables that are allowable for compliance under the rule as currently proposed. When renewables are included, the 2012 emissions rate is 1,714 lbs/MWh.

provided by the Company in Colorado follow a forecasted trajectory similar to EPA's targets for Colorado. However, many uncertainties remain in knowing what effect this rule will eventually have.

The EPA plans to issue a final rule in the summer of 2015. The State of Colorado will then need to develop a state compliance plan which could be turned into the EPA between 2016 and 2018. Finally, the EPA would need to approve Colorado's state compliance plan before the Company can fully plan for this new rule. The Company is actively following this process and has advocated on behalf of our customers to gain better recognition in the final rule for pre-2012 emissions reduction activities. We plan to continue closely following the rule and will communicate with the Commission as appropriate on rule developments.

Solar*Connect

The Company proposed, in Docket No. C14A-0302E, a new customer-choice program called Solar*Connect. Solar generation for the program would be supplied by a new 50 MW (total maximum size) solar generator(s) with a targeted in-service date no later than December 2016. Based on the location and design of any new solar resource acquired for purposes of the Solar*Connect program, a maximum reduction in incremental resource need of between 16 MW and 24 MW could be realized.[7] The 50 MW solar generator associated with this proposed program was not included as part of the Company's Total Summer Net Dependable Capacity in Table 2 above. In the event the Commission approves the Solar*Connect program the resource need projections in Table 3 for years 2019-2024 could be reduced by up to 24 MW.

Federal Production Tax Credit and Federal Investment Tax Credit

The Federal Production Tax Credit ("PTC") for certain renewable generators, including wind, expired on 12/31/2013. Since its inception in 1992, the PTC has expired and been renewed (sometimes retroactively) five times. The Federal Investment Tax Credit ("ITC") for certain renewable generators, including solar, is scheduled to decline from 30% to 10% after 12/31/2016. In the 2013 All-Source Solicitation, certain wind generation resources afforded the benefit of the PTC and certain solar generation resources afforded the benefit of the 30% ITC were found to be cost-effective for customers compared to other generation alternatives. Absent a re-instatement of the PTC or an extension of the 30% ITC the Company cannot predict whether additional wind and solar generation resources might be cost-effective relative to other alternatives in the next competitive solicitation.

[7] The Company's most recent Electrical Load Carrying Capability study for solar generation shows values between 0.31 and 0.47 based on location and tracking capability. 50 * 0.31 = 15.5 MW; 50 * 0.47 = 23.5 MW.

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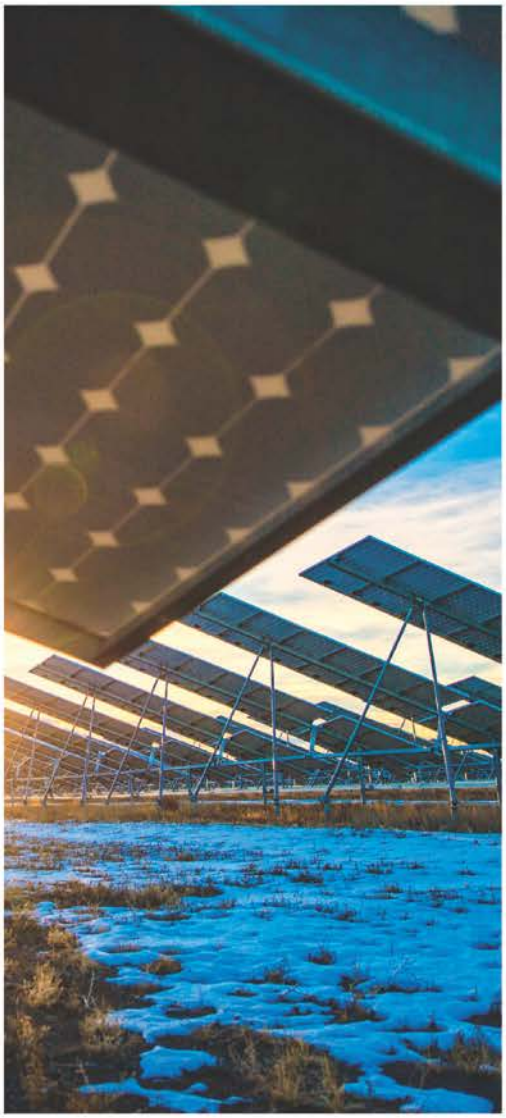

Colorado PUC E-Filings System

Public Service Company of Colorado

2016 Electric Resource Plan
Volume 1

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

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TABLE OF CONTENTS

1.0 **EXECUTIVE SUMMARY** 5

1.1 **INTRODUCTION AND BACKGROUND** 9

Purpose of Filing 9
Contents and Organization of the 2016 ERP 9
Procedural Background 10
High Level 2016 ERP Process Overview 11
Summary and Status Update of 2011 ERP 12

1.2 **LANDSCAPE** 14

Public Service System Energy Mix 14
Energy Markets in Transition 17
Energy Market Dynamics and External Factors 19
Clean Power Plan and Carbon Regulation Policy 22
Other Environmental Regulatory Challenges 23

1.3 **RESOURCE ACQUISITION PERIOD AND PLANNING PERIOD** 28

Resource Acquisition Period 28
Planning Period 29

1.4 **RESOURCE NEED ASSESSMENT** 30

Reliability/Capacity Need Assessment 30
RES Compliance Need Assessment 35
Flexible Generation Need Assessment 35
EPA Clean Power Plan Need Assessment 36

1.5 **ALTERNATIVE PLANS** 39

Section Overview 39
Resource Technologies Used in Alternative Plan Analysis 41
Major Assumptions Used in Modeling of Alternative Plans 44
Alternative Plans 46
Alternative Plan Development Process 46
Organization of Alternative Plan Analysis Discussion 48
RAP Additions Analysis - Alternative Plans 49
General Observations on PVRR Cost 51
PTC Analysis 52
PTC Analysis Observations 53
ITC Analysis 54
ITC Analysis Observations 55
Carbon Emission Analysis 55
Carbon Emission Analysis Observations 57
RESA Deferred Balance Analysis 57
Additional Sensitivity Analysis 58
Gas Price Sensitivity Analysis Observations 59
Sales Forecast Sensitivity Analysis Observations 61
Post-RAP Additions Analysis - Alternative Plans 62

General Observations on PVRR Cost 63
Carbon Emission Analysis 64
Carbon Emission Analysis Observations 65
RESA Deferred Balance Analysis 65
Gas Price Sensitivity Analysis Observations 67

1.6 **RESOURCE ACQUISITION PLAN** 68

Phase II Capacity Need 68
Minimum Bid Size 70
Company Ownership 71
Demand-Side Management Resources 71
120-Day Report 72

1.7 **RESERVE MARGIN AND CONTINGENCY PLAN** 73

Planning Reserves For The 2016 ERP 73
Contingency Plan 73

LIST OF TABLES

TABLE 1.1-1 2013 All-Source Solicitation Resources And Procurement Status 13
TABLE 1.2-1 Percent Of 2016 Emissions Avoided By Source 16
TABLE 1.2-2 Percent Of 2023 Emissions Avoided By Source 16
TABLE 1.4-1 ERP Phase I L&R Projection Of Resource Need (MW) 32
TABLE 1.4-2 Approximate Impact On Resource Need (MW) 34
TABLE 1.5-1 Generic Dispatchable Resource Cost And Performance 43
TABLE 1.5-2 Renewable Resource Cost And Performance 44
TABLE 1.5-3 Analysis Of PTC Level And Wind In-Service Year 53
TABLE 1.5-4 Analysis Of ITC Level And Solar In-Service Year 54
TABLE 1.5-5 RAP Additions CO_2 And Renewable Generation 56
TABLE 1.5-6 Additional Sensitivity Assumptions 58
TABLE 1.5-7 RAP Additions Gas Price Sensitivity Analysis 59
TABLE 1.5-8 RAP Additions Low Sales Sensitivity Analysis 60
TABLE 1.5-9 RAP Additions High Sales Sensitivity Analysis 61
TABLE 1.5-10 Post-RAP Additions Analysis 62
TABLE 1.5-11 Post-RAP Additions Analysis - Renewables TO 2040 63
TABLE 1.5-12 Post-RAP CO_2 And Renewable Generation 64
TABLE 1.5-13 Post-RAP Gas Price Sensitivity Analysis 67

LIST OF FIGURES

FIGURE 1.1-1 High Level 2016 ERP Process Overview 12
FIGURE 1.2-1 Projected System Energy Mix In 2016 And 2025 14
FIGURE 1.2-2 Public Service CO_2 Reduction By Source 15
FIGURE 1.2-3 2016 ERP Gas Price Forecast 21
FIGURE 1.2-4 Denver Ozone Non-Attainment Area 26
FIGURE 1.4-1 Basic Reliability/Capacity Need Assessment 31
FIGURE 1.5-1 Alternative Plan Analysis Framework 40
FIGURE 1.5-2 RAP Additions Analysis - Alternative Plans 1, 2, 3, And 4 49
FIGURE 1.5-3 RAP Additions Analysis - Renewables To 2040 51
FIGURE 1.5-4 PVRR Comparison Of Table 1.5-3 Combinations 53
FIGURE 1.5-5 PVRR Comparison Of Table 1.5-4 Combinations 55
FIGURE 1.5-6 RAP Additions And Resa Deferred Balance 58
FIGURE 1.5-7 Post-RAP RESA Deferred Balance 66

1.0 EXECUTIVE SUMMARY

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

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

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

Building on the circumstances and issues identified in the 2011 ERP, the Company's projection of need for additional generation resources is being influenced by a number of factors that have resulted in a greater level of uncertainty in these projections than in prior ERPs. While there has always been uncertainty as to the

economic expectations included in the Company's forecast of electric demand and energy over the years, Public Service is now facing a convergence of issues associated with an energy market that is in transition. The following summary lists some of the near-term issues that have the potential to affect the customer electric demand, and thus affect the resource need to be filled in this ERP:

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

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

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

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

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

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

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

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

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

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

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

1.1 INTRODUCTION AND BACKGROUND

Purpose of Filing

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

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

Contents and Organization of the 2016 ERP

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

Volume 1: 2016 ERP

Volume 2: Technical Appendix and References

Volume 3: Requests for Proposals and Model Agreements

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

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

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

Procedural Background

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

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

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

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

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

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

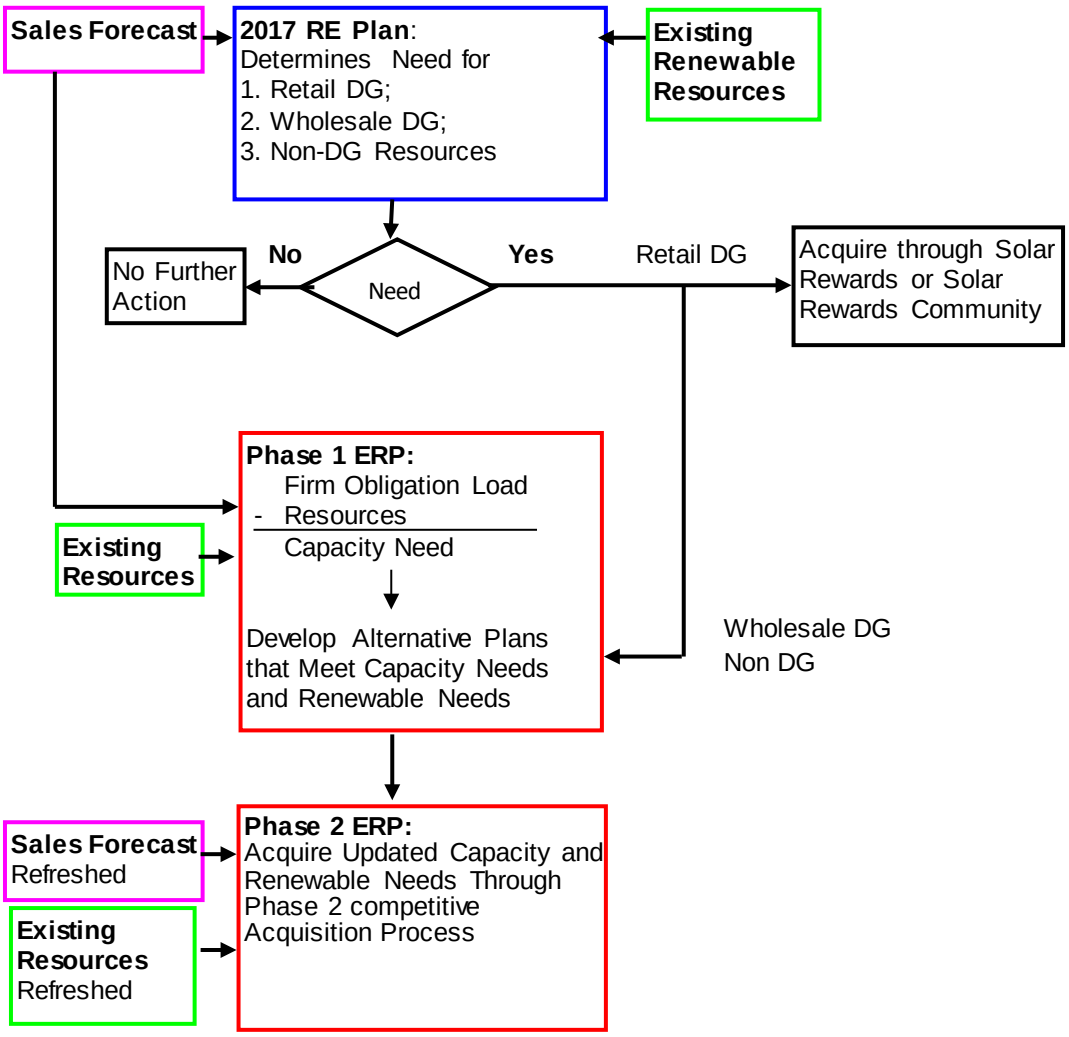
High Level 2016 ERP Process Overview

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

Public Service's 2017 RE Plan, described later in this document, identifies that the Company does not need to acquire any additional Wholesale DG or Non-DG eligible energy resources in the RAP in order to comply with the RES.[1]

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

Figure 1.1-1 High Level 2016 ERP Process Overview



Summary and Status Update of 2011 ERP

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

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

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

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

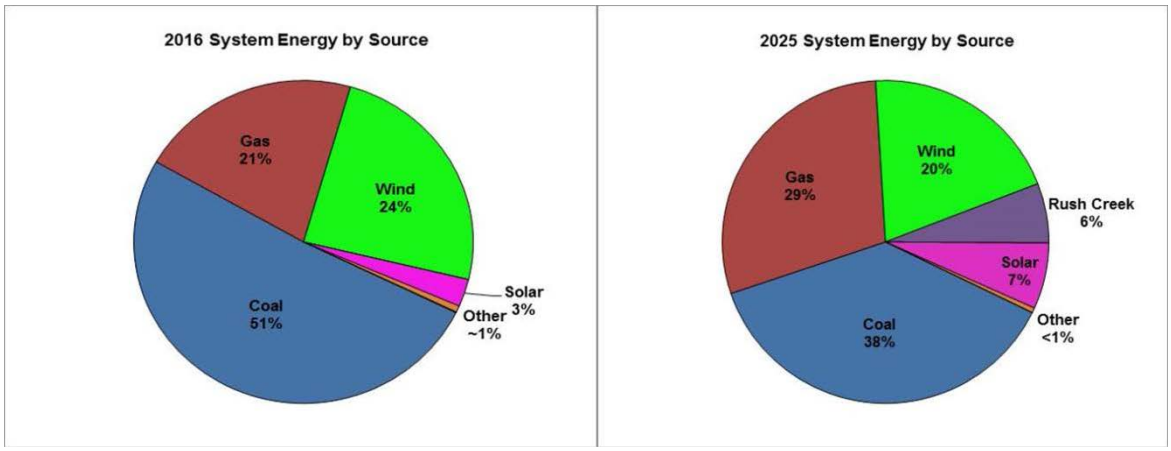
1.2 LANDSCAPE

Public Service System Energy Mix

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

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

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



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

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

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

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

Figure 1.2-2 Public Service CO_2 Reduction by Source

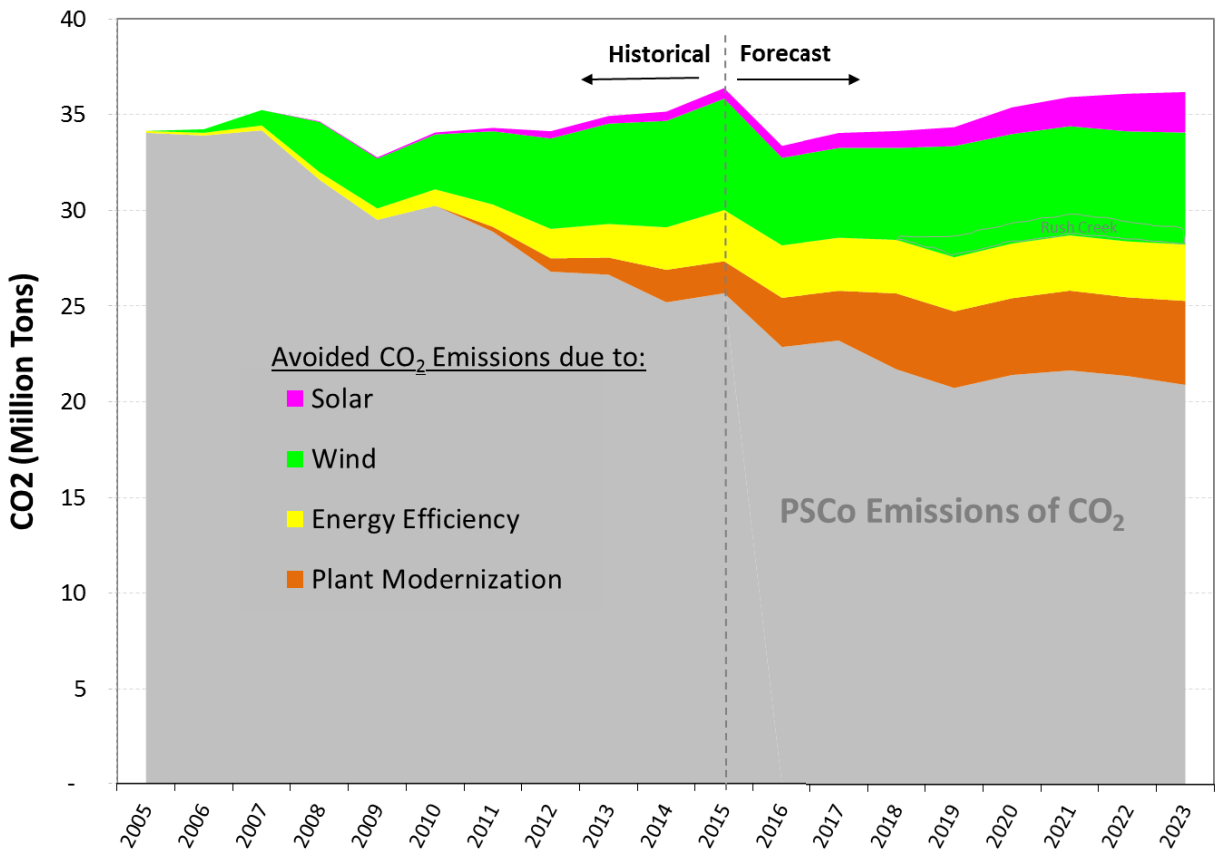


Figure 1.2-2 details the reductions in CO_2 emissions on the Public Service system from both historical and planned actions. Overall, system CO_2 emissions decreased from a total of ~34 million tons in 2005 to ~26 million tons in 2015. System emissions are projected to drop even further to a level of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

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

Table 1.2-1 Percent of 2016 Emissions Avoided by Source

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

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

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

Table 1.2-2 Percent of 2023 Emissions Avoided by Source

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

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

Energy Markets in Transition

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

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

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

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

Public Service's Solar*Rewards program has been very successful in creating a distributed generation program in the state. Over the last 5 years, the Company has averaged installations of approximately 36 MW of rooftop solar each year. In the 2017 RE Plan, the Company is proposing to increase this opportunity to approximately 90 MW per year for the years 2017 through 2019. After 2019, the Company has included a placeholder of the same approximate 105 MW per year in its planning models for additional customer

choice solar. The overall net impact of the Company's 2017 RE Plan filing and the placeholder we have included in the 2016 ERP is a decrease in total need of approximately 215 MW through 2023. To the extent the implementation of this program deviates from the capacity quantities listed above, the Company could end up either long (i.e., having additional generation resources) or short on resources. In the latter case, the Company could face a situation where it may need to acquire extra resources.

The Company's proposed Solar*Connect program

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

Utilization of more energy efficient appliances and lighting

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

Significantly lower oil and natural gas prices

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

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

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

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

Energy Market Dynamics and External Factors

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

Low Natural Gas and Oil Prices

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

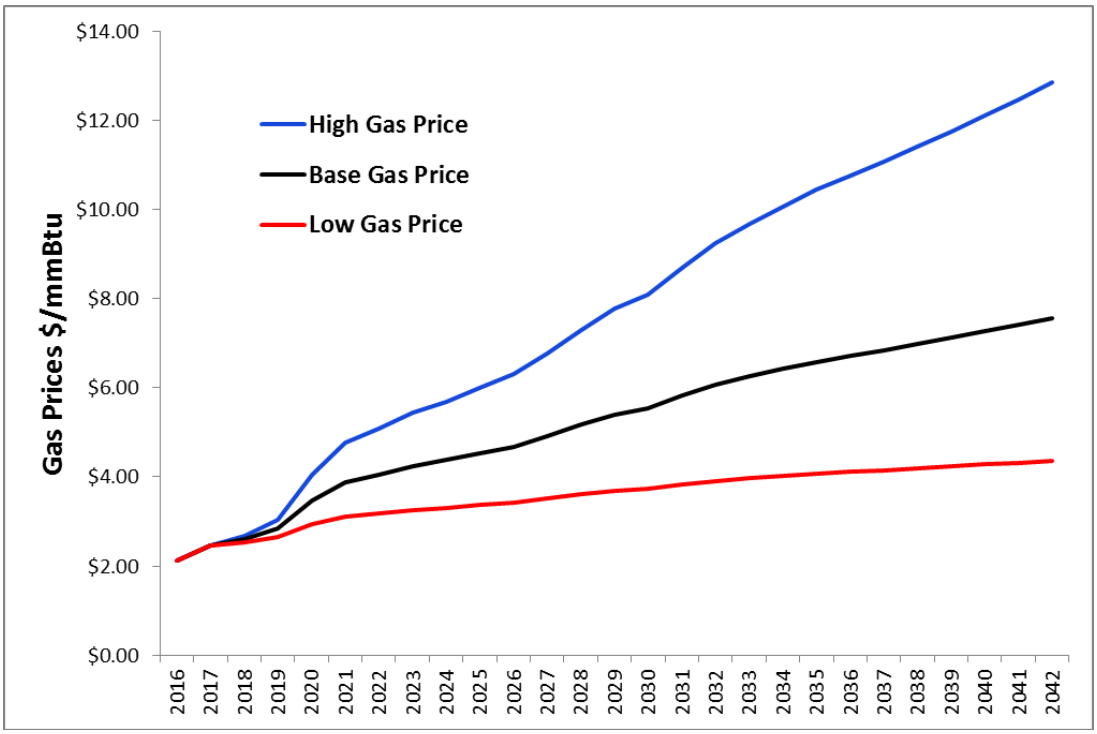
This low price natural gas environment, combined with low oil prices, has put significant financial strain on producers and a number of them have filed bankruptcy

as their ability to access the capital markets has become constrained. This financial stress has forced producers to become very innovative by reducing rig counts, improving drilling efficiency, controlling costs and focusing on their most productive drilling locations.

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

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

Figure 1.2-3 2016 ERP Gas Price Forecast



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

The price of natural gas is a key driver in determining the cost-effectiveness of renewable resources such as wind and solar relative to gas-fired resources. Low gas prices make wind and solar less competitive with gas-fired resources while higher gas prices make them more competitive.

Federal Tax Credit Extensions

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

Production Tax Credit - Wind

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

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

Investment Tax Credit - Solar

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

Clean Power Plan and Carbon Regulation Policy

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

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

This stay adds more uncertainty to the rule, creating up to two years of delay. A decision from the D.C. Circuit Court is not expected until late 2016 at the earliest, following oral arguments. This means the Supreme Court could hear the case sometime in the fall of 2017 or spring of 2018, depending on when the D.C. Circuit issues its decision. The potential outcomes include the rule being upheld, the rule

being struck down, or the rule being upheld in part and vacated in part, among other potential outcomes. No matter what the courts ultimately decide, we believe that U.S. or state-level climate policy remains a strong likelihood for the industry, although the CPP's future is now more uncertain.

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

Other Environmental Regulatory Challenges

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

Regional Haze

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

that planning period to 2021 for better integration with other air quality programs such as the control of ozone and reductions in greenhouse gas emissions.

Clean Air-Clean Jobs Act

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

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

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

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

Hazardous Air Pollutants

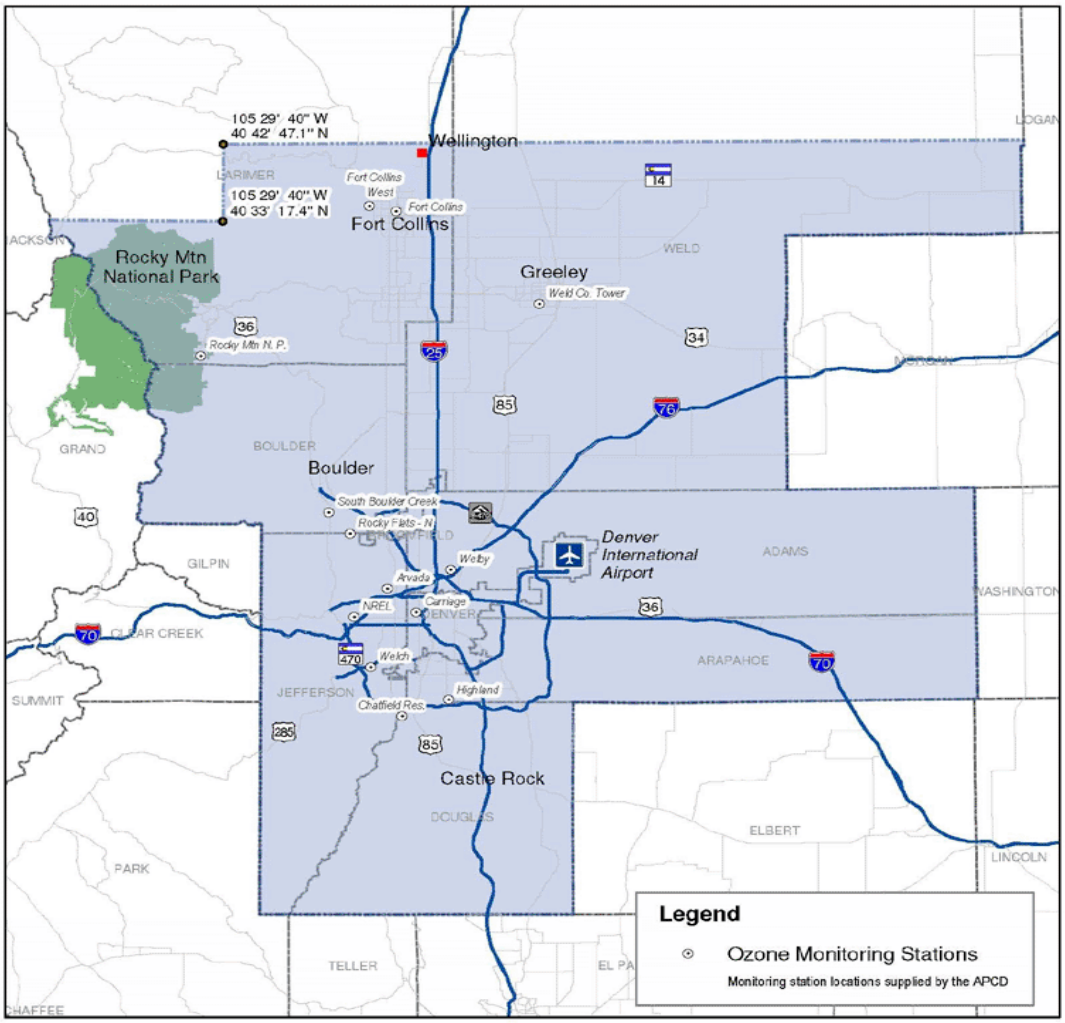
In April 2015, EPA implemented new rules for the control of hazardous air pollutants ("HAPs") from coal-fired electric generating units. These rules required the

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

Ozone

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

Figure 1.2-4 Denver Ozone Non-Attainment Area



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

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

Regulation of Coal Ash

Public Service's power plant operations generate solid wastes that are subject to the federal Resource Conservation and Recovery Act and comparable Colorado laws that impose detailed requirements for the handling, storage, treatment and disposal of solid wastes. In April 2015, EPA finalized a rule regulating coal combustion residuals ("CCRs," sometimes

referred to as "coal ash") as non-hazardous waste and created a broad framework of technical and operational requirements for CCR management and disposal. The rule will impact the storage and disposal of fly ash in landfills and bottom ash in surface impoundments by requiring liners for new CCR Units, additional operational plans and inspections, detailed groundwater monitoring, and inactive CCR Unit closure requirements. The rule requires much operational data to be posted on a publically-accessible website and enforcement of the rule will be accomplished through citizen suits, both of which could impose significant public scrutiny on the company and its CCR operations.

Clean Water Act – "Waters of the United States"

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

1.3 RESOURCE ACQUISITION PERIOD AND PLANNING PERIOD

Resource Acquisition Period

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

i. PTC and ITC extensions

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

ii. Length of time between bid submittal and resource need

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

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

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

iv. Timing of the 2019 ERP

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

Planning Period

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

1.4 RESOURCE NEED ASSESSMENT

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

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

Reliability/Capacity Need Assessment

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

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

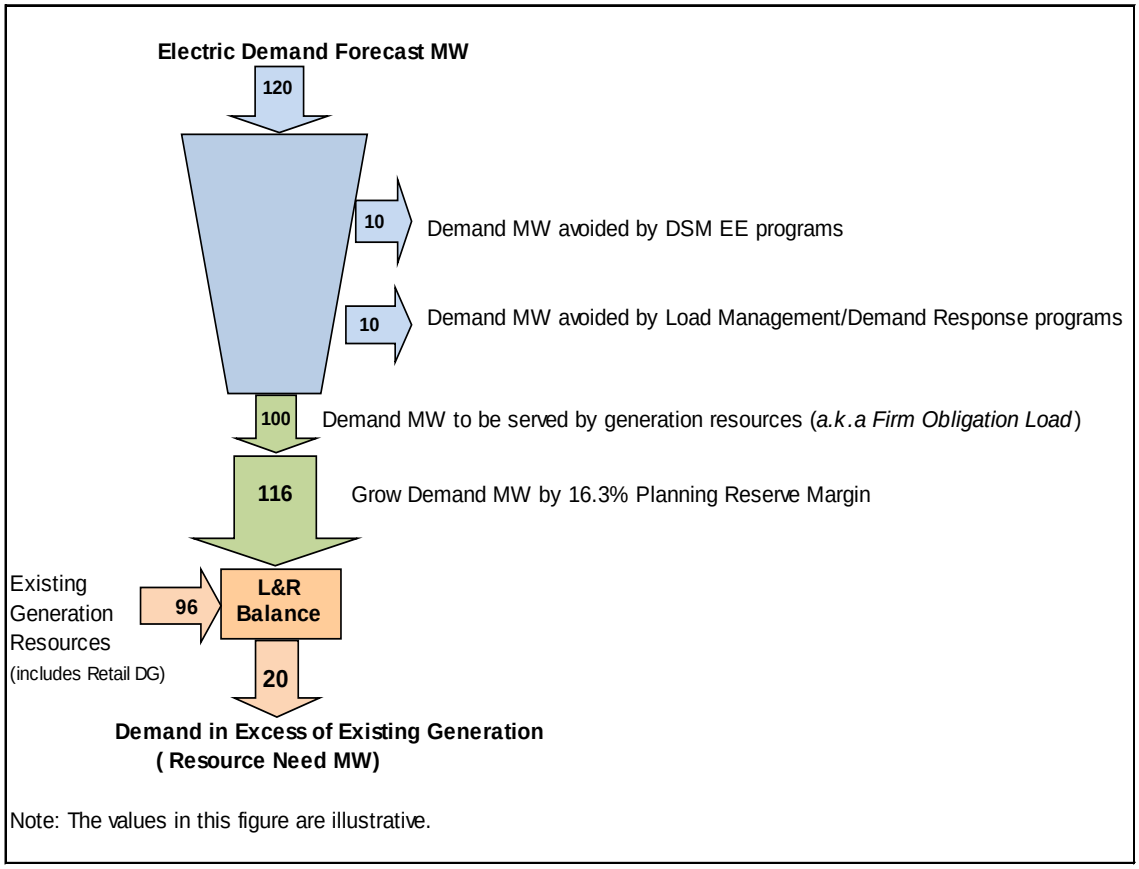
- ERP Phase II L&R – developed prior to receipt of bids in the 2016 ERP Phase II acquisition process to represent the resource needs to be filled through that process. This Phase II L&R is certain to show a different level of

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

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

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

Figure 1.4-1 Basic Reliability/Capacity Need Assessment



The assessment accounts for the reduction in peak demand resulting from the Company's DSM programs and demand response programs. Also captured in this assessment is the estimate of generation from retail DG resources over the RAP as

a result of the Company's Solar*Rewards and Solar*Community solar gardens programs.

ERP Phase I L&R

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

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

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

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

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

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

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

Uncertainty in Phase II Resource/Capacity Need Assessment

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

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

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

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

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

gas loads at levels 50% lower than anticipated would decrease the Company's 2023 resource need by ~125 MW.

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

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

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

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

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

Notes:

1) Total nameplate of customer choice assumed to be added from 2017-2023 is approxmately 600 MW

2) Differences due only to Econometric factors

3) Residential Demand Rates could be enabled by AMI infrastructure and the forthcoming Grid CPCN filing

4) High/Low Oil and Gas Load sensitivities assume +/- 50% of expected impact respectively

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

RES Compliance Need Assessment

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

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

Flexible Generation Need Assessment

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

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

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

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

EPA Clean Power Plan Need Assessment

Background

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

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

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

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

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

Current Company Actions

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

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

General Company Assessment

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

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

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

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

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

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

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

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

1.5 ALTERNATIVE PLANS

Section Overview

Commission Rule 3604(k) requires utility resource plans to provide descriptions of a "baseline case" and "alternate plans" that can be used to estimate the costs and benefits of increasing amounts of Section 124 renewable energy resources, demand-side resources, or Section 123 Resources that could potentially be part of a cost-effective resource plan. This section of the 2016 ERP describes how Public Service developed alternative plans to meet this rule requirement.

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

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

Figure 1.5-1 Alternative Plan Analysis Framework[10]

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

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

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

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

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

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

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

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

Resource Technologies Used in Alternative Plan Analysis

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

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

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

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

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

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

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

Table 1.5-1 Generic Dispatchable Resource Cost and Performance

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

Notes:

(1) All Costs in year 2015 dollars

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

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

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

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

(6) Based on Siemens 5000F 2x1 CC

(7) Based on Siemens 5000F SC

The capital costs used to represent gas-fired combined cycle and combustion turbine technologies in Table 1.5-1 are reflective of the midpoint of a cost range for these facilities depending on whether they are developed as “Greenfield” facilities under an Engineering, Procurement and Construction (“EPC”) approach or as “brownfield” expansions on existing Company generation sites under a Company managed approach.

Table 1.5-2 Renewable Resource Cost and Performance

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

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

Major Assumptions Used in Modeling of Alternative Plans

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

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

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

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

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

Discussion on Integration Costs for Intermittent Generation

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

1. Wind Integration Costs

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

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

2. Solar Integration Costs

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

3. Coal Cycling

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

4. Flexible Generation

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

Alternative Plans

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

Alternative Plan Development Process

Step 1 - Construct Strategist Model

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

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

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

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

The resulting model representation showed a need for additional generation capacity within the 8-year RAP totaling approximately 615 MW in order to meet a 16.3% planning reserve margin. The base model also has a need for additional generation capacity to meet a 16.3% planning reserve margin for all future years beyond the RAP. The need for additional capacity both within the RAP and beyond arises from a combination of electric load growth and assumed Company owned resource retirements and PPA expirations.

Step 2 - Develop Alternative Plan 1 (Baseline Case)

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

Step – 3 Develop Alternative Plans

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

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

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

Alternative Plan 1 – No New Renewables

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

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

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

Organization of Alternative Plan Analysis Discussion

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

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

RAP Additions Analysis - Alternative Plans

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

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

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

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

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

and 2) would be offered back to Public Service rather than offered to another electric utility in the state.

Figure 1.5-3 RAP Additions Analysis - Renewables to 2040

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

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

General Observations on PVRR Cost

The results of the RAP additions analysis in Figure 1.5-2 indicate that under base assumptions the combination of combustion turbines and renewable resources are a lower cost option for meeting the RAP needs that is an all-gas portfolio. Additional

wind at both the 100% PTC level and 80% PTC level shows reduced costs compared to the all-gas alternative plan 1 Case ($440 million and $590 million less costs respectively). Similarly, when utility-scale solar that qualifies for the full 30% ITC is added in Alternative Plan 4, it reduces that plan cost by $130 million compared to Alternative Plan 2 which includes only wind.

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

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

PTC Analysis

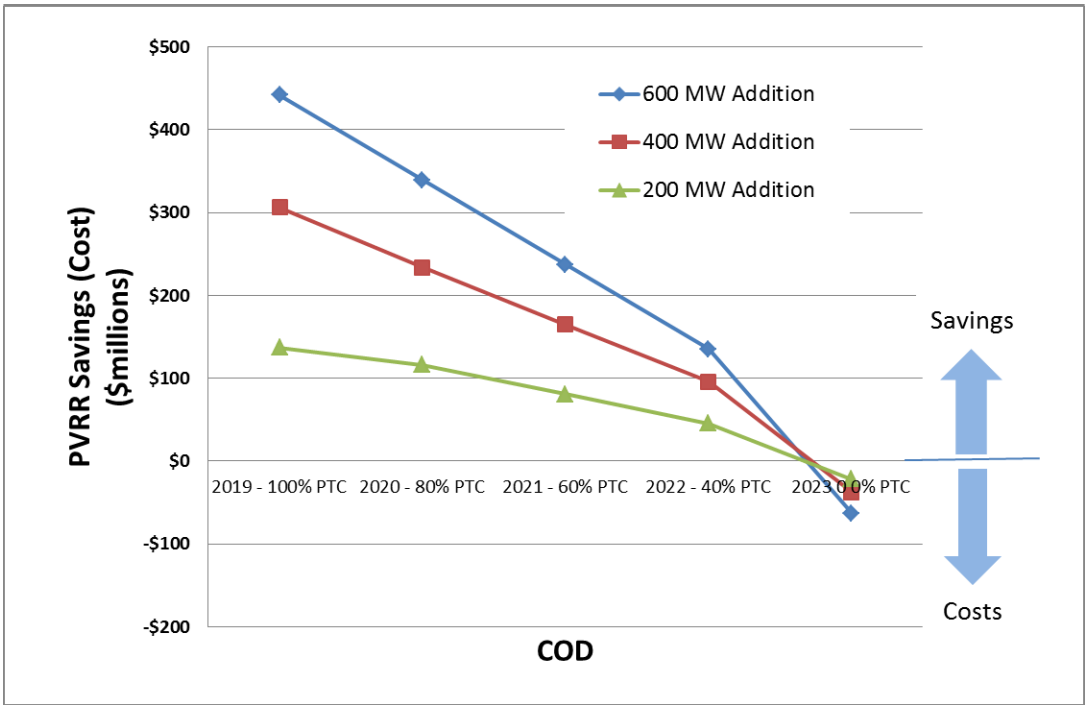
As part of the analysis of alternative plans, Public Service evaluated the system costs and benefits associated with adding wind resources that qualify for 100% of the PTC versus the lower levels of qualification (i.e., 80%, 60%, 40% and 0%). The analysis also involved examining two lesser levels of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

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

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

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

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



PTC Analysis Observations

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

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

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

ITC Analysis

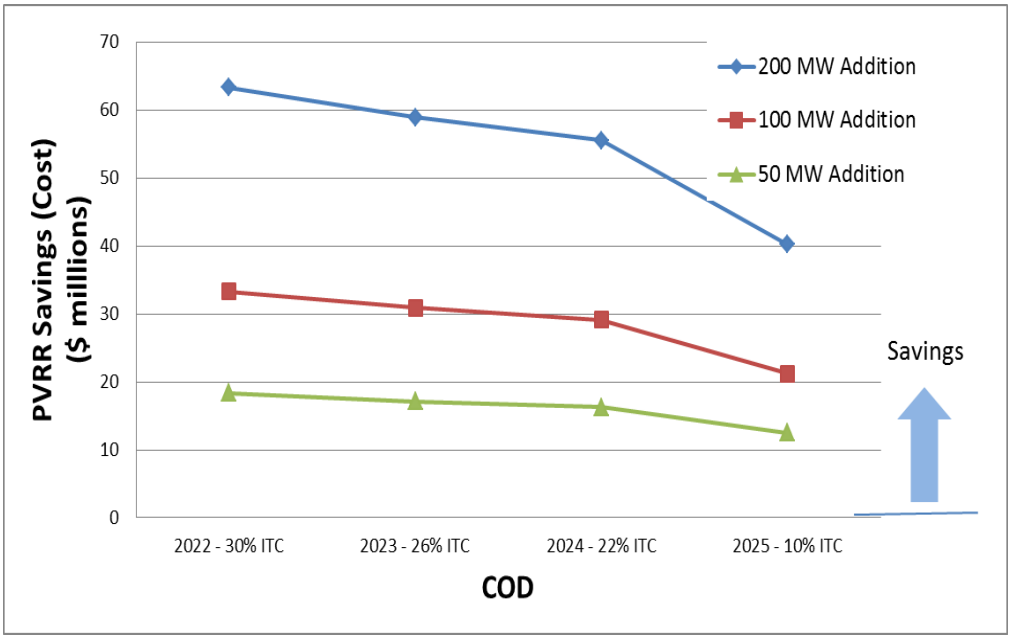
Similar to the PTC analysis discussed above, Public Service evaluated the economic value associated with solar resources that qualify for the 30% ITC versus the lower levels of qualification (i.e., 26%, 22%, and 10%) specified in the Consolidated Appropriations Act, 2016. This analysis examined three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

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

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

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

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



ITC Analysis Observations

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

Carbon Emission Analysis

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

implementation plan, given that the specifics of that state plan have not yet been developed.

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

Table 1.5-5 RAP Additions CO_2 and Renewable Generation

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

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

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

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

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

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

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

Carbon Emission Analysis Observations

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

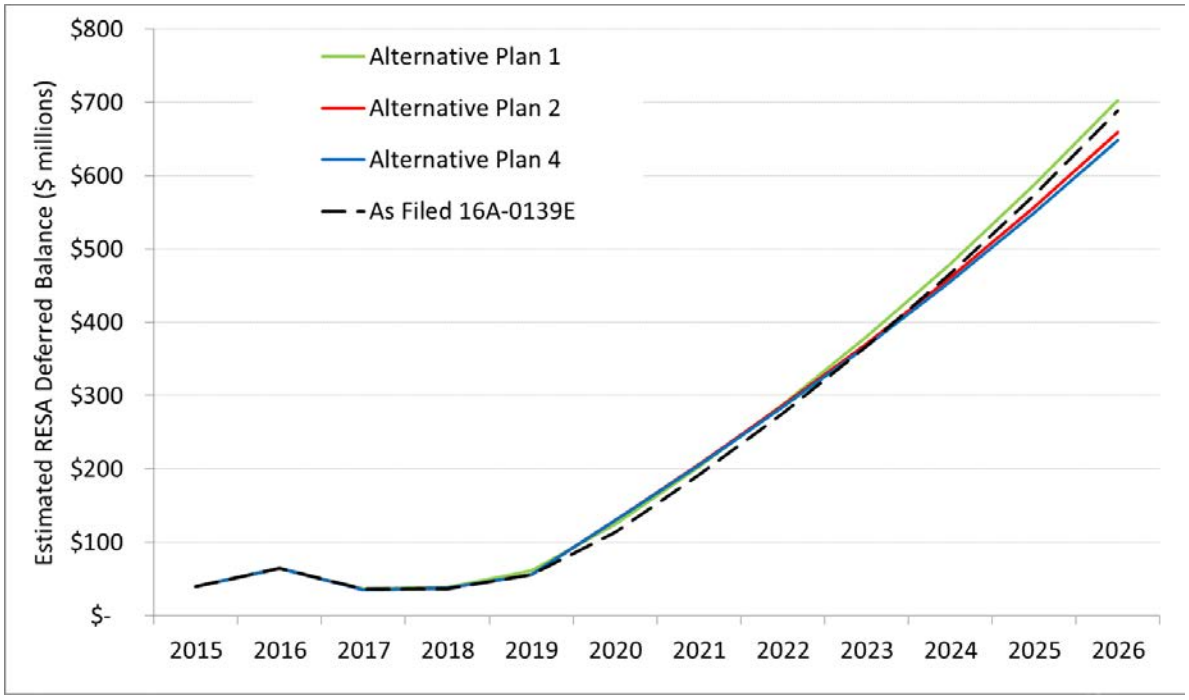
RESA Deferred Balance Analysis

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

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

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

Figure 1.5-6 RAP Additions and RESA Deferred Balance



Additional Sensitivity Analysis

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

Table 1.5-6 Additional Sensitivity Assumptions

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

Gas Price Sensitivity Analysis

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

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

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

Table 1.5-7 RAP Additions Gas Price Sensitivity Analysis

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

2016-2054 PVRR Deltas from Baseline ($M)

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

Gas Price Sensitivity Analysis Observations

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

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

Sales Forecast Sensitivity Analysis

The low and high sales sensitivity analyses required that a new "base model" be developed within which the four alternative plans discussed above could be evaluated and compared with one another. The need to develop another "base model" stems from the fact that fewer or greater levels of generic resources are needed in order to serve the different levels of energy sales and demand contained in the low and high sales forecasts. Tables 1.5-8 and 1.5-9 summarize the results of these low and high sales forecasts sensitivities.

Table 1.5-8 RAP Additions Low Sales Sensitivity Analysis

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

2016-2054 PVRR Deltas from Baseline ($M)

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

Table 1.5-9 RAP Additions High Sales Sensitivity Analysis

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

2016-2054 PVRR Deltas from Baseline ($M)

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

Sales Forecast Sensitivity Analysis Observations

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

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

Post-RAP Additions Analysis - Alternative Plans

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

Table 1.5-10 Post-RAP Additions Analysis

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

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

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

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

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

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

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

General Observations on PVRR Cost

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

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

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

Carbon Emission Analysis

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

Table 1.5-12 Post-RAP CO_2 and Renewable Generation

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

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

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

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

Carbon Emission Analysis Observations

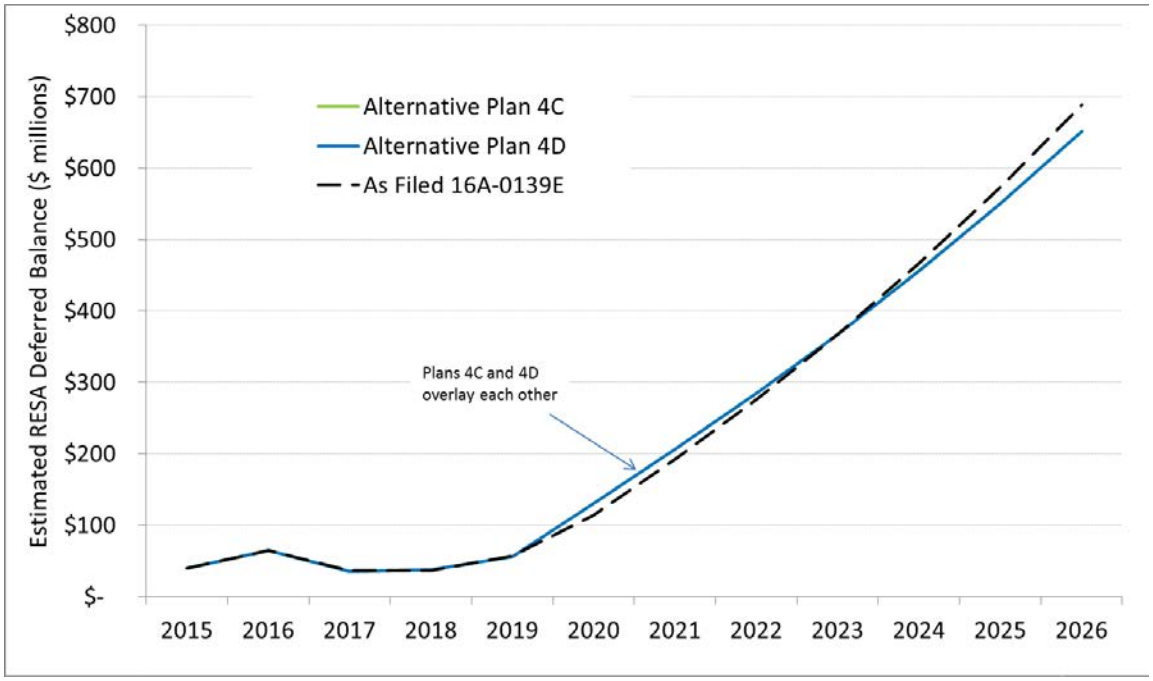
As stated previously, absent the details that a state CPP compliance plan would provide, the Company is limited in its ability to provide a substantive discussion that addresses how the various Post-RAP alternative plans might position Public Service to comply with the CPP carbon reduction targets through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

RESA Deferred Balance Analysis

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

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

Figure 1.5-7 Post-RAP RESA Deferred Balance



Gas Price Sensitivity Analysis

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

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

Table 1.5-13 Post-RAP Gas Price Sensitivity Analysis

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

Gas Price Sensitivity Analysis Observations

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

1.6 RESOURCE ACQUISITION PLAN

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

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

Phase II Capacity Need

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

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

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

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

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

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

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

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

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

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

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

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

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

Minimum Bid Size

While Rule 3611(a) establishes that a competitive acquisition process will normally be used to acquire power supply resources and that the process should afford an opportunity for all technologies to bid, Rule 3615(a)(III) allows the Company to acquire generation resources no larger than 30 MW outside of an approved ERP. However, in order to more fully consider and evaluate all available power supply options available to the Company in this ERP, Public Service proposes that supply-side electric generation technologies with a nameplate electric rating greater than 100 kW would be eligible for consideration. Such a minimum project size will allow the Company to determine if the credits afforded to small, supply-side resources interconnecting at distribution voltages can overcome typically lower-cost supplies from larger generation projects employing similar generation technologies. Minimum project sizes greater than 100 kW will also allow the Company to evaluate other proposed technologies that may not currently scale to larger sizes, such as Section 123 proposals.

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

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

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

Company Ownership

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

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

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

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

Demand-Side Management Resources

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

accept proposals offering additional DSM resources as part of the 2016 ERP Phase II competitive acquisition process.

120-Day Report

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

1.7 RESERVE MARGIN AND CONTINGENCY PLAN

Planning Reserves for the 2016 ERP

For the 2016 ERP, Public Service proposes to utilize a planning reserve margin target of 16.3% in assessing the need for additional power supply resources. This 16.3% value will be applied to the Company's projection of annual firm peak demand[35] over the RAP to determine the amount of additional power supply the Company should seek to acquire in this ERP in order to maintain acceptable long-term system reliability. The appropriateness of a 16.3% planning reserve target for the Public Service system was established through a collaborative study effort between the Commission Staff, the Office of Consumer Counsel, and the Company. The study determined that a 16.3% planning reserve margin for the Public Service system would result in a "loss of load probability" ("LOLP") of 1-day in 10-years, a common industry standard for an acceptable level of system reliability.

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

Contingency Plan

Public Service recognizes that matching electric generation with customer demand will not always proceed according to plan. Problems can arise as a result of delays in the in-service dates of new generation facilities, contract negotiations with suppliers can breakdown, and unanticipated increases in the customer demand can arise that Public Service is obligated to serve. While it is impossible to anticipate everything that can occur in the resource acquisition process, the Company's contingency plan focuses on events that could contribute to a capacity shortfall situation. Two key factors dictate whether a particular corrective action will provide a a viable solution for a particular contingency event. These factors are the magnitude of the potential resource shortfall, and the timing associated with the potential capacity shortfall – both the lead-time to the contingency and the duration of the event.

In the event Public Service faces a capacity shortfall situation, the appropriate course of action will depend largely on the specifics of the shortfall itself, i.e., magnitude and timing, as well as a variety of other factors, e.g., market conditions, other acquisition activities underway. As such, Public Service will always need to apply judgment as to how we should proceed when deciding what corrective action to pursue. For this reason, the Public Service contingency plan reflects a large

[35] Annual firm peak demand to which the 16.3% reserve margin target will be applied is represented by taking the 50th percentile forecast of total peak demand projection and subtracting the effects of the Company's energy efficiency and firm interruptible load programs.

degree of flexibility in how we plan to address various contingencies. Section 2.6 of Volume 2 provides a more detailed discussion of the Contingency Plan and includes Table 2.6-1 Hierarchy of Contingency Plan Alternatives, which lists several possible approaches for addressing contingencies that might require corrective action over the acquisition period. This hierarchy depends on how long before the event Public Service becomes aware of the contingency, the expected duration of the contingency, e.g., a delay versus the permanent loss of a planned resource, and the magnitude of the contingency.

Public Service and other Xcel Energy Inc. electric operating companies have successfully applied many of these contingency actions in the past. Xcel Energy Inc.'s other utility operating companies also have experience with many of these measures and Public Service can draw upon a wide range of resources, experience and capabilities in order to respond in the most appropriate way to contingencies that might develop during the RAP for the 2016 ERP.

Colorado PUC E-Filings System

CITY OF BOULDER, COLORADO

REQUEST FOR PROPOSALS

PARTIAL REQUIREMENTS WHOLESALE ELECTRIC POWER SUPPLY

ISSUE DATE: April 16, 2015

DUE DATE: May 18, 2015

BOULDER RESERVES THE RIGHT TO REJECT ANY OR ALL OFFERS OR PROPOSALS

Table of Contents

PART 1: GENERAL RFP INFORMATION 4

1.1 INTRODUCTION 4

PART 2: RESOURCES REQUESTED 5

2.2 REQUIRED ENERGY & CAPACITY 5
2.3 DESIRED PRICING STRUCTURE 7

PART 3: RFP PROCESS 7

3.1 RFP SCHEDULE 7
3.2 BID SUBMISSION 7
3.3 BID COMPONENTS 8

PART 4: QUALIFIED BIDDER REQUIREMENTS 9

4.1 BALANCING AREA REQUIREMENTS 9
4.2 FINANCIAL REQUIREMENTS 9

PART 5: SERVICE ATTACHMENTS 9

5.1 SERVICE ATTACHMENTS 9

PART 6: LOAD INFORMATION 10

6.1 DEFAULT SERVICE LOAD OBLIGATIONS 10
6.2 DEFAULT SERVICE REQUIREMENTS 10
6.3 HISTORICAL DEFAULT SERVICE REQUIREMENTS 10
6.4 LOAD FORECASTING 10

PART 7: BIDDER QUESTIONS 10

7.1 QUESTIONS REGARDING THIS RFP 10
7.2 RFP SCHEDULE 11

APPENDIX 1: REQUIRED FORMS 12

FORM I: BIDDER'S OFFICER'S CERTIFICATE 12
FORM II: STANDARD CONTRACT INFORMATION 15

APPENDIX 2: MASTER POWER PURCHASE AND SALES AGREEMENT 16

COVER SHEET 18
MASTER POWER PURCHASE AND SALES AGREEMENT 28

SCHEDULE P: GENERAL DEFINITIONS 50
CONFIRMATION LETTER 57

1. INTRODUCTION

The City of Boulder ("City") is requesting a bid for wholesale power supply from Public Service Company of Colorado ("PSCo") for a minimum of a five-year period commencing January 1, 2018. The basic premise of the bid should be for a "Slice of the System" (Slice) whereby Boulder agrees to pay a fixed percent of PSCo's power costs in exchange for a fixed percent of the PSCo generation and capabilities. The contract for power should include energy, capacity, ancillary services, renewable energy obligations and losses, and network integration transmission service. The City is requesting a requirements contract for wholesale power less the city's own hydroelectric and local generation.

The City is interested in exploring any contract terms that allows the city to pursue its energy goals related to price stability, clean energy and potential exposure to stranded cost obligation in its effort to create a locally owned and operated electric utility. PSCo is encouraged to propose any pricing structures that seek to satisfy the City's objectives as discussed in Section 2.2 below. While the City of Boulder is releasing the solicitation for wholesale power supply as a request for proposals, it acknowledges that PSCo, as Boulder's current energy supplier, is uniquely positioned to respond to the specific terms of this request. The terms and provisions have been adapted accordingly.

Capitalized terms used but not defined in the body of the Request for Proposals (RFP) have the meanings given such terms in the "Definitions" section of the Master Power Purchase and Sales Agreement ("Standard Contract"), included as Appendix 1 to this RFP. The headings to articles and sections throughout this RFP are intended solely to facilitate reading and do not affect the meaning or interpretation of this RFP or the Standard Contract.

PSCo is invited to submit a proposal ("Bid") for the right to provide the load requirements identified in this RFP. To be considered for selection, PSCo is asked to meet all the requirements set forth in Section 4, Qualified Bidder Requirements, and adhere to the schedule and other requirements set forth in Section 3, RFP Process. The City will base its evaluation and award on (i) pricing, (ii) compliance with the Standard Contract, (iii) the financial and credit risks associated with the Bid, and (iv) compliance with the RFP Process.

The City will evaluate any conforming Bid, however, the City makes no commitment to PSCo that it will receive an award under this RFP. The City reserves the right to modify or discontinue the RFP process at any time for any reason whatsoever. This is an RFP and not a binding offer to contract. If the RFP is modified by the City, including but not limited to the RFP Schedule, PSCo will be notified of any such modifications.

The City also agrees to treat the Pricing Information and any other non-publicly available financial information that is clearly marked "Confidential" that it receives from PSCo and any Guarantor in a confidential manner and will use reasonable efforts, except as required by law or regulatory authority, not to disclose such information to any third party or use such information for any purpose other than in connection with its evaluation of PSCo's participation in the solicitation process described herein.

2. RESOURCES REQUESTED

PSCo shall provide to the City, and the City shall compensate PSCo for:

1) Firm Capacity;

2) Associated Firm Load-Following Energy sufficient to meet 100 percent of the City's Requirements during the Term of this Transaction excluding that portion of Capacity and Energy provided by Behind-the-Meter Generation; and

3) All Ancillary Services from generation resources required to support Firm Network Integration Transmission Service for the City's Network Load under PSCo's Operating Companies' Open Access Transmission Tariff (OATT)

Capacity and energy will be supplied from a portfolio of owned and contracted generation resources substantially the same as those used prior to the Initial Effective Date of this Transaction to serve the Native Load located within the municipal boundaries of the City of Boulder, Colorado.

2.1 REQUIRED ENERGY AND CAPACITY

The City desires to evaluate the costs of potential resource options that may be available from PSCo. The City anticipates an initial peak load of 257 MW by 2018, which includes a 16.3% reserve margin. It is expected that the City's energy needs will be served by a mix of traditional resources, renewable resources, and energy conservation. The City desires that electric energy delivery commence January 1, 2018 and should be for a term of not less than five years. PSCo's submittal should include a thorough description of all required information including the quantity and term of the resources along with any updated historic or forecasted load information for the city of Boulder.

The City estimates Boulder's growth rate at 0.56% in coincident peak demand compared to a Colorado system average of 0.83%. This may be due to Boulder's relatively flat load profile and local investments in energy efficiency and distributed generation. Boulder anticipates gradually introducing into its power supply mix capacity and energy supplied by resources other than those owned by PSCo. Boulder wishes to do so at a pace that ensures, in reference to PSCo's forecasted need in its Electric Resource Plan process, that (1) PSCo is not adding new owned or contracted generating capacity to its system in order to serve Boulder's load, and (2) generating resources previously deployed to meet Boulder's requirements are redirected to providing service to new demand on other portions of the PSCo system in a manner that does not cause any disproportionate increase in the cost of service assigned to meet such new demand.

For energy quantity and scheduling provisions, the table below describes the City's current best estimate of Boulder's total forecasted annual demand and energy growth requirements. These estimates are subject to change as updated information on Boulder's load is received.

Table 1: Summary of City of Boulder forecasted annual demand and energy

Year	Energy (MWh)[1]	Retail Peak Demand (MW)[2]
2018	1,518,124	257
2019	1,528,687	258
2020	1,542,440	259
2021	1,547,969	261
2022	1,557,645	262

The annual forecast for the proposed local electric utility's service area was developed using the growth trajectory from available data and the adjustments in the 2010 hourly ("8760") data spreadsheet, which is also available for download at www.boulderenergyfuture.com.

Table 2 represents a breakdown of Boulders' annual energy requirements by sector. Based on more accurate system use and load projections from PSCo, estimates will be adjusted accordingly.

Table 2: Annual Boulder Energy by Sector (MWh)

Year	Street lights	Residential	Commercial	Primary General & Transmission General	City Retail Total
2018	4,886	273,735	697,578	541,925	1,518,124
2019	4,934	276,996	701,984	544,773	1,528,687
2020	4,981	281,110	708,289	548,060	1,542,440
2021	5,025	283,004	710,551	549,389	1,547,969
2022	5,069	285,991	714,894	551,691	1,557,645

[1] 2011 Electric Resource Plan (ERP) Response by Xcel Energy to Discovery Request BLDR 3-2.A1 (monthly adjusted to annual)

[2] 2011 Electric Resource Plan (ERP) Xcel Energy Response to Discovery Request BLDR 2-3.A1 (provided August 2012)

2.2 DESIRED PRICING STRUCTURE

The City is interested in any pricing structure that aims to balance the city's objectives of price stability and clean energy while limiting the city's exposure to stranded costs and avoiding impact to other rate payers in PSCO's service territory. Therefore, the City encourages PSCo to propose pricing for various contract structures such that Boulder can reduce its purchase of demand and energy from PSCo, commensurate with self-generation or purchases on the market in increasing blocks of power. Options may include but are not limited to:

2.2.1 Resources priced at PSCo's system average embedded cost for capacity and system average cost for Energy ("Slice of System").

2.2.2 Resources priced at a fixed or preset market-based price.

2.2.3 Resources priced at PSCo's system average embedded cost for capacity and system average cost for Energy ("Slice of System") modified such that Boulder's resource mix contains a higher percentage of renewable energy than is provided, on average, to PSCo retail customers e.g. 5%, 10%, 15% and 20%.

2.2.4 Resources priced at PSCo's system average embedded cost for capacity and system average cost for Energy ("Slice of System") modified such that Boulder can reduce its purchase of demand and energy from PSCo, commensurate with PSCo's reported resource need[3] of 34MW in 2020, 104MW in 2021 and 435 MW in 2022.

For comparison purposes, the desired pricing format is a firm, fixed price on both capacity ($/kW-year or $/kW-month) and energy ($/MWh) for a term not less than five years in length beginning January 1, 2018. Additional pricing information is included in section 3.3.3 below. If there are pricing variations based on on-peak/off-peak or seasonal periods, PSCo is asked to provide the specifics.

3. RFP PROCESS

3.1 RFP SCHEDULE. Table 3 hereto provides the schedule for this RFP. The City, at its sole discretion, may modify and/or supplement the schedule at any time.

3.2 BID SUBMISSION

3.2.1 Writing; Delivery. Bids must be in writing and delivered to the office of Energy Strategy and Utility Development via electronic mail as set forth below. Supplementary delivery options are also offered below for back-up purposes and

[3] Need shown in Loads and Resources Table: 2014 Annual ERP Report

for Supporting Information which is not available in electronic form. Any deliveries under this section should be confirmed by phone with Jonathan Koehn at (303) 441-1915.

3.2.1.1 By hand or delivery to:

Jonathan Koehn
1101 Arapahoe Ave., 1st Floor
Boulder, Colorado 80302

3.2.2 Numbering. Items in the submittal should refer to the appropriate numbered bidding instruction items in this section of the RFP.

3.3 BID COMPONENTS. Bids must include the following parts.

3.3.1 Supporting Information consists of the following documents, collectively the "Supporting Information":

3.3.1.1 Required Forms. PSCo is asked to complete and execute all Forms in Appendix 1.

3.3.1.2 Standard Contract. The City requests that PSCo abide by the form of Standard Contract included as Form 2 to this RFP (the "2015 Contract"). If PSCo deems changes to be necessary, PSCo should submit the required changes with the bid for review and consideration.

3.3.1.3 PSCo must describe in detail any circumstance in which it or an affiliate was deemed to be in default or noncompliance of a wholesale contract, Billing Policy or Financial Assurance Policy obligation within the past five (5) years.

3.3.1.4 The City reserves the right to require Bidder to provide such other information and financial assurances as the City, in its discretion, deems adequate to demonstrate that Bidder can and will fully honor its obligations under the Standard Contract.

3.3.1.5 PSCo must provide the names of outside advisors engaged or planned to be engaged (if any) to assist in this transaction.

3.3.1.6 PSCo must provide a list of contacts (including e-mail addresses, and telephone and fax numbers) with whom the City may discuss the Bid and, who will be available on the dates that Pricing Information is submitted until the applicable Service Attachment(s) are executed.

3.3.2 Executed Documents Prior to Submission of Pricing Information. To qualify for submission of Pricing Information, PSCo must submit by the applicable due dates in Table 1 the following:

3.3.2.1 Standard Contract. A final form of the Standard Contract must be provided to the City.

3.3.2.2 Financial Security. Security associated with the Standard Contract in the form of either (i) a Guaranty acceptable to the City, substantially in the form of the Standard Guaranty or (ii) an alternative acceptable form of financial security as described in Section 3.2.2 below, must be provided to the City.

3.3.3 Pricing Information. Subject to satisfaction of the above requirements, PSCo must submit its Pricing Information as follows:

3.3.3.1 Pricing Information submitted as of the time and dates that the Pricing Information component of the Bids are due shall be firm, irrevocable and binding.

PSCo must complete and submit Exhibit A: Master Power Purchase and Sales Agreement. The completed Agreement becomes PSCo's Pricing Information.

3.3.3.2 The desired pricing format is a firm, fixed price on both capacity ($/kW-year or $/kW-month) and energy ($/MWh) for a term not less than five years in length and beginning January 1, 2018. Monthly prices will be rounded to the nearest thousandths of cents/kWh (i.e., three digits beyond the decimal point) prior to evaluation.

3.3.3.3 Upon selection as a winning Bidder, PSCo agrees that the Pricing Information component of its Bid shall remain binding until it is reflected in a fully executed and binding Service Attachment(s).

4. QUALIFIED BIDDER REQUIREMENTS

4.1 BALANCING AREA REQUIREMENTS. In Form I, PSCo must certify that it has or will provide balancing requirements for the City's load.

4.2 FINANCIAL REQUIREMENTS TO BID. Financial performance assurance requirements are designed to achieve two goals: (i) to determine PSCo's eligibility to bid, and (ii) to protect the City and Retail Customers from non-performance risks. PSCo must demonstrate in its Bid that it has the financial resources and experience to meet the terms and conditions of the Standard Contract and perform such Standard Contract if selected as a winning Bidder.

5. SERVICE ATTACHMENTS

5.1 SERVICE ATTACHMENTS. Awards made to PSCo shall be included as attachments to the Standard Contract. See Exhibit 1, Form of Service Attachment, to the Standard Contract for the form of those attachments.

6. LOAD INFORMATION

6.1 LOAD SERVICE OBLIGATIONS. PSCo is responsible for forecasting and satisfying Load obligations on an hourly, daily, and monthly basis during the Term of Agreement.

6.2 SERVICE REQUIREMENTS. Load Service Requirements are expected to vary in quantity hourly throughout the Term of Agreement. The quantity of purchased energy may change with time, and PSCo must supply all such requirements during the Term of Agreement. PSCo must be (i) prepared to supply its contracted-for Load Service Requirements, regardless of fluctuations in Retail Customer demand during the Term of Agreement and (ii) capable of meeting the hourly, daily and seasonal electricity load fluctuations associated with their Load Service Requirements.

6.3 HISTORICAL LOAD SERVICE REQUIREMENTS. PSCo has access to Boulder forecast obligations pursuant to Section 6.1. The City does not represent or warrant the accuracy of this information, and shall have no liability or responsibility to any entity resulting from the provision or use of this information. PSCo's submittal should include a thorough description of all required information including the quantity and term of the resources along with any updated historic or forecasted load information for the city of Boulder as discussed in Section 2.1.

6.3.1 Load Data. Projected load requirements are located in Section 2.1.

6.3.2 The effect of customer migration can be significant, particularly with regard to the Larger Customers. Bidder is advised to carefully review the historical loads for all Customer classifications as part of the bidding process.

6.4 LOAD FORECASTING. Historical values reflect changes in load due to demand-side management or on-site generation. The City makes no representation regarding the projections of the aggregated load or the load of such customers, and the City shall have no liability or responsibility to any entity resulting from the provision or use of any such information. No penalties or limitations on load reduction efforts including local demand-side management (DSM) and on-site distributed generation will be applied.

6.4.1 Because the load for the Customer classifications may vary, PSCo will be required to supply the contracted-for percentage of load and all Services for the duration of the Term of Agreement of the final Standard Contract, not a particular megawatt level.

6.4.2 Load Profiles. Forecasted energy by sector can be found in Section 2.1.

7. BIDDERS' QUESTIONS

7.1 The City will be available throughout the solicitation process to receive questions. PSCo should submit all inquiries or requests for additional information in email form to: koehnj@bouldercolorado.gov

7.2 RFP SCHEDULE

TABLE 3 - RFP Schedule

Action item	**Date**
Release of RFP	April 16, 2015
Bid Due	May 18, 2015
Bidders' Executed Standard Contract and related Financial Security Due	May 18, 2015
Bidders' Pricing Information Due	May 18, 2015

APPENDIX 1

Form I: Bidders Officer's Certificate

Form II: Standard Contract Information

Form I: Bidder's Officers Certificate

This Form I is provided to the City by Public Service Company of Colorado (PSCo) ("Bidder") in satisfaction of the requirements of the Default Service of the City's Request for Proposals, dated April 16, 2015.

PSCo hereby certifies to the City that the information contained in and submitted pursuant to this Certificate is accurate and complete. Capitalized terms used but not defined herein have the meanings given such terms in the RFP and the Default Service Wholesale Sales Agreement.

1. **General Bidder Information:**

Bidder's Name:			
Bidder's Address:			
Contact Name and Title:			
Contact Phone #:		Contact Fax #:	
Contact E-Mail Address:			
Federal Tax ID:		Duns #:	
Legal Structure:	( )Corporation ( )Parent ( )Subsidiary ( )Division ( )Single Entity ( )Proprietorship ( )Partnership		
State of Residency or Organization:_____		Date of Incorporation or Date Business Started:_____	

2. **General Guarantor Information (if applicable):**

Guarantor Name:			
Guarantor Address:			
Contact Name/Title:			
Contact Phone#		Contact Fax #:	
Contact E-Mail Address:			
Federal Tax ID:		Duns #:	
Legal Structure:	( )Corporation ( )Parent ( )Subsidiary ( )Division ( )Single Entity ( )Proprietorship ( )Partnership		
State of Residency or Organization:_____		Date of Incorporation or Date Business Started:_____	

3. **Financial Qualifications of Guarantor or of Bidder with Investment Grade Company Status**

a. Name of Company

b. Investment Grade Company Status

Rating Agency	Credit Rating	Date of Rating
S&P	_____	_____
Moody's	_____	_____
Fitch's	_____	_____

c. Tangible Net Worth – Provide in accordance with Section 1.80 of the Standard Contract:

_____

d. Acceptable Financial Assurance.

If Bidder cannot establish or have Guarantor establish Investment Grade Company status, Bidder shall qualify for participation in the RFP by providing in advance of submitting Pricing Information financial assurance to the City from a U.S. commercial bank or a U.S. branch of a foreign bank with such bank having assets totaling not less than USD ten billion ($10,000,000,000) and having a Credit Rating of at least A3 from Moody's, A- from S&P or Fitch, or an equivalent Credit Rating by another nationally recognized rating service reasonably acceptable to the City, in the form of a Letter of Credit or other acceptable security that the City in its sole discretion deems to be sufficient to secure all of Bidder's obligations to the City, including, but not limited to, its obligations under this RFP and the Standard Contract.

4. **Financial Information**

a. **General Financial Information.** Attached hereto are audited annual financial statements of Guarantor (or of Bidder if Bidder has Investment Grade Company status), for the most recent fiscal year and quarterly financial statements for the most recent fiscal quarter, if applicable, all in reasonable detail and duly certified (subject to yearend audit adjustments) by the Chief Financial Officer, Treasurer, Assistant Treasurer or Comptroller of the Guarantor (or of Bidder if Bidder has Investment Grade Company status) as having been prepared in accordance with generally accepted accounting principles consistently applied.

b. **Publicly Owned Companies.** The following documents have been made available through an internet address (or otherwise) to the City for Guarantor (or for Bidder if Bidder has Investment Grade Company status) for the three previous fiscal years:

Annual Report
Form 10K (most recent)
Form 10Q (most recent)
All Form 8Ks (since last 10Q)

c. **Privately Owned Companies.** Attached is a copy, duly certified (subject to year end audit adjustments) by the Chief Financial Officer, Treasurer, Assistant Treasurer or

Comptroller of the Guarantor (or of the Bidder if Bidder has Investment Grade Company status) as having been prepared in accordance with generally accepted accounting principles consistently applied of the following information for the three previous fiscal years:

Balance Sheet
Income Statement
Statement of Changes in Cash Flow
Notes to Financial Statements (most recent)

The annual financial statements must be audited by a licensed certified public accountant and accompanied by the auditor's opinion letter.

5. **Organization Structure.** Attached to this Certificate is a complete and accurate copy of the current Organizational Chart of Bidder showing relationships between parent, subsidiaries, relevant affiliated entities and joint ventures.

6. **Regulatory and Colorado Compliance.** Bidder has or will obtain all regulatory authorizations necessary for it to legally perform its obligations under the Bid which this Certificate accompanies, and the Default Service Wholesale Sales Agreement and/or any Service Attachment(s) that may be entered into with the City; the execution, delivery, and performance of such a contract will be within its lawful powers; such contract will be duly authorized by all necessary business entity actions and will not violate any of the terms or conditions in its governing documents, any contracts or other agreement to which it is a party or any law applicable to it; and this Bid does and such contract, if entered into, will constitute its legally valid and binding obligation enforceable against it in accordance with its terms, subject to any equitable defense.

Form II: Standard Contract Information

The following information will be used to complete the relevant Standard Contract sections for the Bidder without an existing contract. Please see the appropriate section of the Standard Contract for full descriptions of the requested information.

1) Please provide a copy of the tariff that you will be providing service under, as well as the following information.

   Electric Rate Schedule Number: _____ FERC Docket Number: _____

2) Please provide contact information for any notices, demands or requests.

   Name or Title:
   Full Address:
   City, State, Zip
   Telephone:
   Fax:
   E-mail:

3) Please provide contact information for correspondence related to load reporting.

   Name or Title:
   Telephone:
   Fax:
   E-mail:

4) Signature page (if information is presently known).

   Name:

   Title:

MASTER POWER PURCHASE AND SALES AGREEMENT

TABLE OF CONTENTS

COVER SHEET 18

GENERAL TERMS AND CONDITIONS 28

ARTICLE ONE: GENERAL DEFINITIONS 28

ARTICLE TWO: TRANSACTION TERMS AND CONDITIONS 33
2.1 Transactions 33
2.2 Governing Terms 33
2.3 Confirmation 33
2.4 Additional Confirmation Terms 34
2.5 Recording 34

ARTICLE THREE: OBLIGATIONS AND DELIVERIES 34
3.1 Seller's and Buyer's Obligations 34
3.2 Transmission and Scheduling 35
3.3 Force Majeure 35

ARTICLE FOUR: REMEDIES FOR FAILURE TO DELIVER/RECEIVE 35
4.1 Seller Failure 35
4.2 Buyer Failure 35

ARTICLE FIVE: EVENTS OF DEFAULT; REMEDIES 35
5.1 Events of Default 35
5.2 Declaration of an Early Termination Date and Calculation of Settlement Amounts 37
5.3 Net Out of Settlement Amounts 37
5.4 Notice of Payment of Termination Payment 37
5.5 Disputes With Respect to Termination Payment 37
5.6 Closeout Setoffs 38
5.7 Suspension of Performance 38

ARTICLE SIX: PAYMENT AND NETTING 38
6.1 Billing Period 38
6.2 Timeliness of Payment 39
6.3 Disputes and Adjustments of Invoices 39
6.4 Netting of Payments 39
6.5 Payment Obligation Absent Netting 40
6.6 Security 40
6.7 Payment for Options 40
6.8 Transaction Netting 40

ARTICLE SEVEN: LIMITATIONS 40
7.1 Limitation of Remedies, Liability and Damages 40

ARTICLE EIGHT: CREDIT AND COLLATERAL REQUIREMENTS 41
8.1 Party A Credit Protection 41
8.2 Party B Credit Protection 43
8.3 Grant of Security Interest/Remedies 44

ARTICLE NINE: GOVERNMENTAL CHARGES 45
9.1 Cooperation 45
9.2 Governmental Charges 45

ARTICLE TEN: MISCELLANEOUS 45
10.1 Term of Master Agreement 45
10.2 Representations and Warranties 46
10.3 Title and Risk of Loss 47
10.4 Indemnity 47
10.5 Assignment 47
10.6 Governing Law 48
10.7 Notices 48
10.8 General 48
10.9 Audit 49
10.10 Forward Contract 49
10.11 Confidentiality 49

SCHEDULE P: PRODUCTS AND RELATED DEFINITIONS 50

EXHIBIT A: CONFIRMATION LETTER 57

MASTER POWER PURCHASE AND SALE AGREEMENT
COVER SHEET

This *Master Power Purchase and Sale Agreement* ("*Master Agreement*") is made as of the following date: _____ ("Effective Date"). The *Master Agreement*, together with the exhibits, schedules and any written supplements hereto, the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any confirmations accepted in accordance with Section 2.3 hereto) shall be referred to as the "Agreement." The Parties to this *Master Agreement* are the following:

Party A: [BOULDER LIGHT & POWER]

All Notices:

Street:

City/State:

Zip:

Attn:
Phone:
Facsimile:
Duns: 07-575-9969
Federal Tax ID Number: 84-6000566

Invoices:
Attn:
Phone:
Facsimile:

Scheduling:
Attn:
Phone:
Facsimile:

Confirmations:
Attn:
Phone:
Facsimile:

Payments:
Attn:
Phone:
Facsimile:

Wire Transfer:
BNK:
ABA:
ACCT:

Credit and Collections:
Attn:
Phone:
Facsimile:

Party B:

All Notices:

Street:

City/State:

Zip:

Attn:
Phone:
Facsimile:
Duns:
Federal Tax ID Number:

Invoices:
Attn:
Phone:
Facsimile:

Scheduling:
Attn:
Phone:
Facsimile:

Confirmations:
Attn:
Phone:
Facsimile:

Payments:
Attn:
Phone:
Facsimile:

Wire Transfer:
BNK:
ABA:
ACCT:

Credit and Collections:
Attn:
Phone:
Facsimile:

With additional Notices of an Event of Default or Potential Event of Default to: Attn: Phone: Facsimile:	With additional Notices of an Event of Default or Potential Event of Default to: Attn: Phone: Facsimile:

The Parties hereby agree that the General Terms and Conditions, Version 2.1 (modified 04/25/00) published by the Edison Electric Institute and the National Energy Marketers Association, a copy of which is attached hereto, are incorporated herein. The Parties further agree to the following provisions as provided for in the General Terms and Conditions:

Party A Tariff	Tariff N/A	Dated N/A	Docket Number N/A
Party B Tariff	Tariff	Dated	Docket Number

Article Two

Transaction Terms and Conditions — [X] Optional provision in Section 2.4. If not checked, inapplicable.

Article Four

Remedies for Failure to Deliver or Receive — [X] Accelerated Payment of Damages. If not checked, inapplicable.

Article Five

Events of Default; Remedies

[ ] Cross Default for Party A: Not applicable

[ ] Party A:_____ Cross Default Amount

[ ] Other Entity: Cross Default Amount

[ ] Cross Default for Party B: Not applicable

[ ] Party B: Cross Default Amount

[ ] Other Entity: Cross Default Amount

5.6 Closeout Setoff

[X] Option A (Applicable if no other selection is made.)

[ ] Option B - Affiliates shall have the meaning set forth in the Agreement unless otherwise specified as follows:_____

[ ] Option C (No Setoff)

Article 8

Credit and Collateral Requirements

8.1 Party A Credit Protection:

(a) Financial Information:

[X] Option A
[ ] Option B Specify:
[ ] Option C Specify: _____

(b) Credit Assurances:

[ ] Not Applicable
[X] Applicable

(c) Collateral Threshold:

[X] Not Applicable
[ ] Applicable

If applicable, complete the following:

Party B Collateral Threshold: $ _____; provided, however, that Party B's Collateral Threshold shall be zero if an Event of Default or Potential Event of Default with respect to Party B has occurred and is continuing.

Party B Independent Amount: $_____

Party B Rounding Amount: $_____

(d) Downgrade Event:

[ ] Not Applicable
[X] Applicable

If applicable, complete the following:

[X] It shall be a Downgrade Event for Party B if Party B's Credit Rating falls below BBB- from S&P or Baa3 from Moody's or if Party B is not rated by either S&P or Moody's.

[ ] Other:
Specify:_____

(e) Guarantor for Party B:_____

Guarantee Amount:_____

8.2 Party B Credit Protection:

(a) Financial Information:

[X] Option A
[ ] Option B Specify: _____
[ ] Option C Specify: _____

(b) Credit Assurances:

[ ] Not Applicable
[X] Applicable (as amended)

(c) Collateral Threshold:

[X] Not Applicable
[ ] Applicable

If applicable, complete the following:

Party A Collateral Threshold: $ _____; provided, however, that Party A's Collateral Threshold shall be zero if an Event of Default or Potential Event of Default with respect to Party A has occurred and is

continuing.

Party A Independent Amount: $_____

Party A Rounding Amount: $_____

(d) Downgrade Event:

[ ] Not Applicable
[X] Applicable

If applicable, complete the following:

[X] It shall be a Downgrade Event for Party A if Party A's Credit Rating falls below _____ from S&P or _____ from Moody's or if Party A is not rated by either S&P or Moody's

[ ] Other:
Specify:_____

(e) Guarantor for Party A:_____

Guarantee Amount:_____

Article 10

Confidentiality [X] Confidentiality Applicable If not checked, inapplicable.

Schedule M

[X] Not Applicable
[ ] Party A is a Governmental Entity or Public Power System
[ ] Party B is a Governmental Entity or Public Power System
[ ] Add Section 3.6. If not checked, inapplicable
[ ] Add Section 8.6. If not checked, inapplicable

Other Changes

The following changes shall be applicable.

ARTICLE ONE: GENERAL DEFINITIONS

The following definitions are hereby amended as follows:

Section 1.12 "Credit Rating" is amended by deleting the word "issues" in line 4 and replacing it with "issuer."

Section 1.23 "Force Majeure" is amended by adding the following sentence at the end thereof: "If the Claiming Party is Party A, Force Majeure does not include any action taken by Party A in its governmental capacity."

Section 1.27 "Letter(s) of Credit" is amended by deleting the phrase "or a foreign bank with a U.S. branch" and replacing it with the phrase "or a U.S. branch of a foreign bank."

Sections 1.35 "Option Buyer" and 1.36 "Option Seller" are amended by deleting, in each section, the phrase "as defined in Schedule P."

Section 1.50 "Recording" is amended by replacing the reference to Section 2.4 with a reference to Section 2.5.

Section 1.51 "Replacement Price" is amended by (i) adding the phrase "for delivery" immediately before the phrase "at the Delivery Point" in the second line, and (ii) deleting the phrase "at Buyer's option" from the fifth line and replacing it with the following: "absent a purchase."

Section 1.52 "S&P" is amended by (i) deleting the words "the Standard & Poor's Rating Group" from the first line and replacing them with "Standard & Poor's Financial Services LLC" and (ii) by replacing the words in the parenthetical with "a subsidiary of The McGraw-Hill Companies, Inc."

Section 1.53 "Sales Price" is amended by (i) deleting the phrase "at the Delivery Point" from the second line, and (ii) deleting the phrase "at Seller's option" from the fifth line and replace it with the following: "absent a sale."

ARTICLE TWO: TRANSACTION TERMS AND CONDITIONS

Section 2.4 "Additional Confirmation Terms" is amended by deleting the words "either orally or" in line 7.

ARTICLE FIVE: EVENTS OF DEFAULT; REMEDIES

(a) Section 5.2 "Declaration of an Early Termination Date and Calculation of Settlement Amounts" is amended by reversing the placement of "(i)" and "to."

(b) Section 5.5 "Disputes With Respect to Termination Payment" is amended by adding the words: "(i) pay the undisputed portion of the Termination Payment to the Non-Defaulting Party and (ii)" after the word "first" in the sixth line; and "disputed portion of the" between the words "the" and "Termination Payment" in the 7th line.

ARTICLE SEVEN: LIMITATIONS

Section 7.1 "Limitation of Remedies, Liability and Damages" is amended by adding the following at the end thereof:

"PARTY A'S LIABILITY IN TORT, IF ANY, ALSO SHALL BE LIMITED BY APPLICATION OF THE COLORADO GOVERNMENTAL IMMUNITY ACT C.R.S. §§ 24-10-101 THROUGH 24-10-120. FOR THE AVOIDANCE OF DOUBT, SUCH APPLICATION SHALL IN NO WAY INFLUENCE PARTY A'S POTENTIAL LIABILITY IN RELATION TO ANY CLAIM IN CONTRACT UNDER THIS AGREEMENT."

ARTICLE EIGHT: CREDIT AND COLLATERAL REQUIREMENTS

(a) Section 8.1(b) "Credit Assurances" is amended by deleting the existing provision in its entirety and substituting therefor the following:

"8.1(b) Credit Assurances. If, from time to time, Party A has reasonable good faith grounds to believe that Party B's creditworthiness or that of its Guarantor, if any, or Party B's ability to perform under this Agreement has become materially impaired, Party A will provide Party B with written notice requesting Performance Assurance, including the basis for such request in reasonable detail, in an amount determined by Party A in a commercially reasonable manner but not to exceed an amount equal to one hundred percent (100%) of the Termination Payment plus Party B's Independent Amount, if any, plus all amounts owed but not yet paid by Party B to Party A, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions (rounding upwards for any fractional amount to the next Party B Rounding Amount), less any Party B Performance Assurance already posted with Party A. Upon receipt of such notice, Party B shall have one (1) Business Day to remedy the situation by providing such Performance Assurance to Party A. In the event that Party B fails to provide such Performance Assurance to Party A within the time period specified in this Section 8.1(b), then an

Event of Default under Article Five will be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement."

(b) Section 8.2(b) Credit Assurances is amended by deleting the existing provision in its entirety and substituting therefor the following:

"8.2(b) Credit Assurances. If, from time to time, Party B has reasonable good faith grounds to believe that Party A's creditworthiness or that of its Guarantor, if any, or Party A's ability to perform under this Agreement has become materially impaired, Party B will provide Party A with written notice requesting Performance Assurance, including the basis for such request in reasonable detail, in an amount determined by Party B in a commercially reasonable manner but not to exceed an amount equal to one hundred percent (100%) of the Termination Payment plus Party A's Independent Amount, if any, plus all amounts owed but not yet paid by Party A to Party B, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions (rounding upwards for any fractional amount to the next Party A Rounding Amount), less any Party A Performance Assurance already posted with Party B. Upon receipt of such notice, Party A shall have one (1) Business Day to remedy the situation by providing such Performance Assurance to Party B. In the event that Party A fails to provide such Performance Assurance to Party B within the time period specified in this Section 8.2(b), then an Event of Default under Article Five will be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement."

(c) Section 8.1(d) "Downgrade Event" is amended by adding the phrase "or fails to maintain such Performance Assurance or guarantee or other credit assurance for so long as the Downgrade Event is continuing" after the words "receipt of notice" in the fifth line.

(d) Section 8.2(d) "Downgrade Event" is amended by adding the phrase "or fails to maintain such Performance Assurance or guarantee or other credit assurance for so long as the Downgrade Event is continuing" after the words "receipt of notice" in the fifth line.

ARTICLE TEN: MISCELLANEOUS

(a) Subsection (ix) of Section 10.2 "Representations and Warranties" is deleted in its entirety and replaced with the following:

"(ix)(A) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code; (B) it is an "eligible contract participant" as such term is defined in the Commodity Exchange Act, as amended (7 U.S.C. § 1(a)(12)); and (C) it is an "eligible commercial entity" as such term is defined in the Commodity Exchange Act, as amended (7 U.S.C. § 1(a)(11))."

(b) Section 10.4 "Indemnity" is amended by adding the following sentence at the end of the Section: "Party A's indemnification obligations with respect to any tort claims are subject to the Colorado Governmental Immunity Act, C.R.S. §§ 24-10-101 through 24-10-120."

(c) Section 10.6 "Governing Law" is amended by adding the following terms at the beginning of the Section: "TO THE EXTENT PERMITTED BY LAW," and replacing the period at the end of the Section with a semicolon and inserting thereafter the following: "PROVIDED, HOWEVER, THAT ANY ISSUE RELATING TO (1) THE POWER OR AUTHORITY OF PARTY A TO ENTER INTO THIS AGREEMENT, (2) THE INTERPRETATION OF PARTY A'S REPRESENTATIONS AND WARRANTIES RELATING TO ITS ORGANIZATION, OR (3) PARTY A'S STATUS AS A QUASI-MUNICIPAL CORPORATION AND POLITICAL SUBDIVISION, SHALL IN ALL CASES BE DETERMINED IN ACCORDANCE WITH THE LAWS OF THE STATE OF COLORADO. EACH PARTY HERETO IRREVOCABLY (I) SUBMITS TO THE NON-EXCLUSIVE JURISDICTION OF THE FEDERAL AND STATE COURTS FOR THE COUNTY OF BOULDER, STATE OF COLORADO; (II) WAIVES ANY OBJECTION WHICH IT MAY HAVE TO THE LAYING OF VENUE OF ANY PROCEEDINGS BROUGHT IN ANY SUCH COURT; AND (III) WAIVES ANY CLAIM THAT SUCH PROCEEDINGS HAVE BEEN BROUGHT IN AN INCONVENIENT FORUM."

(d) Section 10.8 "General" is amended by adding the following to the end thereof:

"Each Party authorizes the other Party to affix an ink or digital stamp of its signature to any Confirmation and agrees to be bound by a document executed in such a manner. This Master Agreement may be signed in any number of counterparts with the same effect as if the signatures to counterparty were upon a single instrument. Delivery of an executed signature page of this Master Agreement and any Confirmation by facsimile or electronic mail transmission shall be effective as delivery of a manually executed signature page."

(e) Section 10.10 "Forward Contract" shall be deleted in its entirety and replaced with the following:

"The Parties acknowledge and agree that (1) each Transaction constitutes a "forward contract" within the meaning of the United States Bankruptcy Code (the "Bankruptcy Code"); (ii) certain Transactions may constitute "swap agreements" within the meaning of the Bankruptcy Code; (iii) all payments made or to be made by one Party to the other Party pursuant to this Agreement are "settlement payments" within the meaning of the Bankruptcy Code; (iv) all transfers of "Performance Assurance" by one Party to the other Party under this Agreement are "margin payments" within the meaning of the Bankruptcy Code; and (v) this Agreement constitutes a "master netting agreement" within the meaning of the Bankruptcy Code. Each Party further agrees that, for purposes of this Agreement, the other Party is not a "utility" as such term is used in 11 U.S.C. Section 366, and each Party agrees to waive and not to assert the applicability of the provisions of 11 U.S.C. Section 366 in any bankruptcy proceeding wherein such Party is a debtor. In any such proceeding, each Party further agrees to waive the right to assert that the other Party is a provider of last resort."

(f) Section 10.11 "Confidentiality" is amended by adding the following sentence at the end thereof: "Party A is a Colorado municipal utility and political subdivision of the State of Colorado and, as such, is subject to the Colorado Sunshine Law (C.R.S. §§ 24-6-101 through 24-6-402) and the Colorado Open Records Act (C.R.S. §§ 24-72-201 through 24-72-309). Nothing in this agreement or in any Confirmation hereunder shall be construed to permit or to require Party A to act in violation of either of the foregoing statutes."

(g) Section 10 is amended by adding the following new Section 10.12 "Additional Party A Representations and Warranties:"

"On the Effective Date and the date of entering into each Transaction, Party A represents and warrants to Party B that:

(i) with respect to this Agreement, all acts necessary to the valid execution, delivery and performance thereof, including without limitation, competitive bidding, public notice, election, referendum, prior appropriation or other required procedures have or will be taken and performed as required under all relevant federal, state and local laws, ordinances or other regulations with which Party A is obligated to comply;

(ii) all persons making up the governing body of Party A are the duly elected or appointed incumbents in their positions and hold such positions in good standing in accordance with all relevant federal, state and local laws, ordinances or other regulations with which Party A is obligated to comply;

(iii) the Term of Agreement does not extend beyond any applicable limitation imposed by all relevant federal, state and local laws, ordinances or other regulations with which Party A is obligated to comply or other relevant constitutional, organic or other governing documents and applicable law;

(iv) its obligations to make payments hereunder do not constitute any kind of indebtedness of Party A or create any kind of lien on, or security interest in, any property or revenues of Party A which is proscribed by any provision of any relevant federal, state and local laws, ordinances or

other regulations with which Party A is obligated to comply or any other relevant constitutional, organic or other governing documents and applicable law, any order or judgment of any court or other agency of government applicable to it or its assets, or any contractual restriction binding on or affecting it or any of its assets;

(v) its ability to pay any and all amounts due and payable under the Agreement, or any potential breach thereof, is not conditioned upon any governmental or administrative appropriation by the City of Boulder, Colorado or any other governmental or administrative authority; and

(vi) Party A covenants, with respect to any contract action brought by Party B, whether in law or equity, to enforce Party A's obligations under this Agreement, that Party A shall not raise sovereign immunity as a defense to such contract action."

(h) Section 10 is amended by adding the following new Section 10.13 "Index Transactions:"

If the Parties enter into a Transaction in which any or all of the pricing component is based on a pricing index, the following shall apply:

(a) Market Disruption. If a Market Disruption Event occurs during the Determination Period, the Floating Price for the affected Trading Day(s) shall be determined pursuant to the Floating Price specified in the Transaction for the first Trading Day thereafter on which no Market Disruption Event exists; provided, however, if the Floating Price is not so determined within three (3) Business Days after the first Trading Day on which the Market Disruption Event occurred or existed, then the Parties shall negotiate in good faith to agree on a Floating Price (or a method for determining a Floating Price), and if the Parties have not so agreed on or before the twelfth Business Day following the first Trading Day on which the Market Disruption Event occurred or existed, then each Party shall reasonably and in good faith obtain a calculation of the relevant Floating Price from a Reference Market-maker, and the Floating Price shall be the average of the two calculations.

"Determination Period" means each calendar month a part or all of which is within the Delivery Period of a Transaction.

"Exchange" means, in respect of a Transaction, the exchange or principal trading market specified in the relevant Transaction.

"Floating Price" means the Contract Price specified in a Transaction that is based upon a Price Source.

"Market Disruption Event" means, with respect to any Price Source, any of the following events: (a) the failure of the Price Source to announce or publish information necessary for determining the Floating Price; (b) the failure of trading to commence or the permanent discontinuation or material suspension of trading in the relevant options contract or commodity on the Exchange or in the market specified for determining a Floating Price; (c) the temporary or permanent discontinuance or unavailability of the Price Source; (d) the temporary or permanent closing of any Exchange specified for determining a Floating Price; or (e) a material change in the formula for or the method of determining the Floating Price.

"Price Source" means, in respect of a Transaction, the publication (or such other origin of reference, including an Exchange) containing (or reporting) the specified price (or prices from which the specified price is calculated) specified in the relevant Transaction.

"Reference Market-maker" means a leading dealer in the relevant market selected by a Party in good faith from among dealers which satisfy all the criteria that such Party applies generally at the time in deciding whether to offer or to make an extension of credit.

"Trading Day" means a day in respect of which the relevant Price Source published the relevant price.

(b) Corrections to Published Prices. For purposes of determining the relevant prices for any day, if the price published or announced on a given day and used or to be used to determine a relevant price is subsequently corrected and the correction is published or announced by the person responsible for that publication or announcement, either Party may notify the other Party of (i) that correction and (ii) the amount (if any) that is payable as a result of that correction. If a Party gives notice that an amount is so payable, the Party that originally either received or retained such amount will, not later than three (3) Business Days after the effectiveness of that notice, pay, subject to any applicable conditions precedent, to the other Party that amount, together with interest at the Interest Rate for the period from and including the day on which payment originally was (or was not) made to but excluding the day of payment of the refund or payment resulting from that correction.

(c) Calculation of Floating Price. For the purposes of the calculation of a Floating Price, all numbers shall be rounded to three (3) decimal places. If the fourth (4th) decimal number is five (5) or greater, then the third (3rd) decimal number shall be increased by one (1), and if the fourth (4th) decimal number is less than five (5), then the third (3rd) decimal number shall remain unchanged."

(i) The following Section shall be added as a new Section 10.14 "FERC Standard of Review; Mobile-Sierra Waiver:"

"(a) Absent the agreement of all Parties to the proposed change, the standard of review for changes to any rate, charge, classification, term or condition of this Agreement, whether proposed by a Party (to the extent that any waiver in subsection (b) below is unenforceable or ineffective as to such Party), a non-party or FERC acting sua sponte, shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) and clarified by *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish County*, 554 U.S. 527 (2008) (the "*Mobile-Sierra*" doctrine).

(b) In addition, and notwithstanding the foregoing subsection (a), to the fullest extent permitted by applicable law, each Party, for itself and its successors and assigns, hereby expressly and irrevocably waives any rights it can or may have, now or in the future, whether under §§ 205 and/or 206 of the Federal Power Act or otherwise, to seek to obtain from FERC by any means, directly or indirectly (through complaint, investigation or otherwise), and each hereby covenants and agrees not at any time to seek to so obtain, an order from FERC changing any section of this Agreement specifying the rate, charge, classification, or other term or condition agreed to by the Parties, it being the express intent of the Parties that, to the fullest extent permitted by applicable law, neither Party shall unilaterally seek to obtain from FERC any relief changing the rate, charge, classification, or other term or condition of this Agreement, notwithstanding any subsequent changes in applicable law or market conditions that may occur. In the event it were to be determined that applicable law precludes the Parties from waiving their rights to seek changes from FERC to their market-based power sales contracts (including entering into covenants not to do so) then this subsection (b) shall not apply, provided that, consistent with the foregoing subsection (a), neither Party shall seek any such changes except solely under the "public interest" application of the "just and reasonable" standard of review and otherwise as set forth in the foregoing section (a)."

SCHEDULE M: GOVERNMENTAL ENTITY OR PUBLIC POWER SYSTEMS

Schedule M is deleted in its entirety.

SCHEDULE P: PRODUCTS AND RELATED DEFINTIONS

Schedule P is amended by inserting the following preamble prior to the text thereof: "No definition contained in Schedule P shall apply to any Transaction under this Agreement unless the Parties shall have specifically incorporated such definition in the Confirmation establishing such Transaction."

IN WITNESS WHEREOF, the Parties have caused this Master Agreement to be duly executed as of the date first above written.

Party A: **[Boulder]**	Party B:
By: _____	By: _____
Name: _____	Name: _____
Title: _____	Title: _____

GENERAL TERMS AND CONDITIONS

ARTICLE ONE: GENERAL DEFINITIONS

1.1 "Affiliate" means, with respect to any person, any other person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

1.2 "Agreement" has the meaning set forth in the Cover Sheet.

1.3 "Bankrupt" means with respect to any entity, such entity (i) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (ii) makes an assignment or any general arrangement for the benefit of creditors, (iii) otherwise becomes bankrupt or insolvent (however evidenced), (iv) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (v) is generally unable to pay its debts as they fall due.

1.4 "Business Day" means any day except a Saturday, Sunday, or a Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

1.5 "Buyer" means the Party to a Transaction that is obligated to purchase and receive, or cause to be received, the Product, as specified in the Transaction.

1.6 "Call Option" means an Option entitling, but not obligating, the Option Buyer to purchase and receive the Product from the Option Seller at a price equal to the Strike Price for the Delivery Period for which the Option may be exercised, all as specified in the Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller will be obligated to sell and deliver the Product for the Delivery Period for which the Option has been exercised.

1.7 "Claiming Party" has the meaning set forth in Section 3.3.

1.8 "Claims" means all third party claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorneys' fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

1.9 "Confirmation" has the meaning set forth in Section 2.3.

1.10 "Contract Price" means the price in $U.S. (unless otherwise provided for) to be paid by Buyer to Seller for the purchase of the Product, as specified in the Transaction.

1.11 "Costs" means, with respect to the Non-Defaulting Party, brokerage fees, commissions and other similar third party transaction costs and expenses reasonably incurred by such Party either in terminating any arrangement pursuant to which it has hedged its obligations or entering into new arrangements which replace a Terminated Transaction; and all reasonable attorneys' fees and expenses incurred by the Non-Defaulting Party in connection with the termination of a Transaction.

1.12 "Credit Rating" means, with respect to any entity, the rating then assigned to such entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) or if such entity does not have a rating for its senior unsecured long-term debt, then the rating then assigned to such entity as an issues rating by S&P, Moody's or any other rating agency agreed by the Parties as set forth in the Cover Sheet.

1.13 "Cross Default Amount" means the cross default amount, if any, set forth in the Cover Sheet for a Party.

1.14 "Defaulting Party" has the meaning set forth in Section 5.1.

1.15 "Delivery Period" means the period of delivery for a Transaction, as specified in the Transaction.

1.16 "Delivery Point" means the point at which the Product will be delivered and received, as specified in the Transaction.

1.17 "Downgrade Event" has the meaning set forth on the Cover Sheet.

1.18 "Early Termination Date" has the meaning set forth in Section 5.2.

1.19 "Effective Date" has the meaning set forth on the Cover Sheet.

1.20 "Equitable Defenses" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

1.21 "Event of Default" has the meaning set forth in Section 5.1.

1.22 "FERC" means the Federal Energy Regulatory Commission or any successor government agency.

1.23 "Force Majeure" means an event or circumstance which prevents one Party from performing its obligations under one or more Transactions, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (i) the loss of Buyer's markets; (ii) Buyer's inability

economically to use or resell the Product purchased hereunder; (iii) the loss or failure of Seller's supply; or (iv) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred. The applicability of Force Majeure to the Transaction is governed by the terms of the Products and Related Definitions contained in Schedule P.

1.24 "Gains" means, with respect to any Party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of a Terminated Transaction, determined in a commercially reasonable manner.

1.25 "Guarantor" means, with respect to a Party, the guarantor, if any, specified for such Party on the Cover Sheet.

1.26 "Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

1.27 "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank having a credit rating of at least A- from S&P or A3 from Moody's, in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

1.28 "Losses" means, with respect to any Party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of a Terminated Transaction, determined in a commercially reasonable manner.

1.29 "Master Agreement" has the meaning set forth on the Cover Sheet.

1.30 "Moody's" means Moody's Investor Services, Inc. or its successor.

1.31 "NERC Business Day" means any day except a Saturday, Sunday or a holiday as defined by the North American Electric Reliability Council or any successor organization thereto. A NERC Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time for the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

1.32 "Non-Defaulting Party" has the meaning set forth in Section 5.2.

1.33 "Offsetting Transactions" mean any two or more outstanding Transactions, having the same or overlapping Delivery Period(s), Delivery Point and payment date, where under one or more of such Transactions, one Party is the Seller, and under the other such Transaction(s), the same Party is the Buyer.

1.34 "Option" means the right but not the obligation to purchase or sell a Product as specified in a Transaction.

1.35 "Option Buyer" means the Party specified in a Transaction as the purchaser of an option, as defined in Schedule P.

1.36 "Option Seller" means the Party specified in a Transaction as the seller of an option , as defined in Schedule P.

1.37 "Party A Collateral Threshold" means the collateral threshold, if any, set forth in the Cover Sheet for Party A.

1.38 "Party B Collateral Threshold" means the collateral threshold, if any, set forth in the Cover Sheet for Party B.

1.39 "Party A Independent Amount" means the amount , if any, set forth in the Cover Sheet for Party A.

1.40 "Party B Independent Amount" means the amount , if any, set forth in the Cover Sheet for Party B.

1.41 "Party A Rounding Amount" means the amount, if any, set forth in the Cover Sheet for Party A.

1.42 "Party B Rounding Amount" means the amount, if any, set forth in the Cover Sheet for Party B.

1.43 "Party A Tariff" means the tariff, if any, specified in the Cover Sheet for Party A.

1.44 "Party B Tariff" means the tariff, if any, specified in the Cover Sheet for Party B.

1.45 "Performance Assurance" means collateral in the form of either cash, Letter(s) of Credit, or other security acceptable to the Requesting Party.

1.46 "Potential Event of Default" means an event which, with notice or passage of time or both, would constitute an Event of Default.

1.47 "Product" means electric capacity, energy or other product(s) related thereto as specified in a Transaction by reference to a Product listed in Schedule P hereto or as otherwise specified by the Parties in the Transaction.

1.48 "Put Option" means an Option entitling, but not obligating, the Option Buyer to sell and deliver the Product to the Option Seller at a price equal to the Strike Price for the

Delivery Period for which the option may be exercised, all as specified in a Transaction. Upon proper exercise of the Option by the Option Buyer, the Option Seller will be obligated to purchase and receive the Product.

1.49 "Quantity" means that quantity of the Product that Seller agrees to make available or sell and deliver, or cause to be delivered, to Buyer, and that Buyer agrees to purchase and receive, or cause to be received, from Seller as specified in the Transaction.

1.50 "Recording" has the meaning set forth in Section 2.4.

1.51 "Replacement Price" means the price at which Buyer, acting in a commercially reasonable manner, purchases at the Delivery Point a replacement for any Product specified in a Transaction but not delivered by Seller, plus (i) costs reasonably incurred by Buyer in purchasing such substitute Product and (ii) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or at Buyer's option, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller's liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party at the Delivery Point.

1.52 "S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

1.53 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells at the Delivery Point any Product not received by Buyer, deducting from such proceeds any (i) costs reasonably incurred by Seller in reselling such Product and (ii) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or at Seller's option, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer's liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party at the Delivery Point.

1.54 "Schedule" or "Scheduling" means the actions of Seller, Buyer and/or their designated representatives, including each Party's Transmission Providers, if applicable, of notifying, requesting and confirming to each other the quantity and type of Product to be delivered on any given day or days during the Delivery Period at a specified Delivery Point.

1.55 "Seller" means the Party to a Transaction that is obligated to sell and deliver, or cause to be delivered, the Product, as specified in the Transaction.

1.56 "Settlement Amount" means, with respect to a Transaction and the Non-Defaulting Party, the Losses or Gains, and Costs, expressed in U.S. Dollars, which such party incurs as a result of the liquidation of a Terminated Transaction pursuant to Section 5.2.

1.57 "Strike Price" means the price to be paid for the purchase of the Product pursuant to an Option.

1.58 "Terminated Transaction" has the meaning set forth in Section 5.2.

1.59 "Termination Payment" has the meaning set forth in Section 5.3.

1.60 "Transaction" means a particular transaction agreed to by the Parties relating to the sale and purchase of a Product pursuant to this Master Agreement.

1.61 "Transmission Provider" means any entity or entities transmitting or transporting the Product on behalf of Seller or Buyer to or from the Delivery Point in a particular Transaction.

ARTICLE TWO: TRANSACTION TERMS AND CONDITIONS

2.1 Transactions. A Transaction shall be entered into upon agreement of the Parties orally or, if expressly required by either Party with respect to a particular Transaction, in writing, including an electronic means of communication. Each Party agrees not to contest, or assert any defense to, the validity or enforceability of the Transaction entered into in accordance with this Master Agreement (i) based on any law requiring agreements to be in writing or to be signed by the parties, or (ii) based on any lack of authority of the Party or any lack of authority of any employee of the Party to enter into a Transaction.

2.2 Governing Terms. Unless otherwise specifically agreed, each Transaction between the Parties shall be governed by this Master Agreement. This Master Agreement (including all exhibits, schedules and any written supplements hereto), , the Party A Tariff, if any, and the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmations accepted in accordance with Section 2.3) shall form a single integrated agreement between the Parties. Any inconsistency between any terms of this Master Agreement and any terms of the Transaction shall be resolved in favor of the terms of such Transaction.

2.3 Confirmation. Seller may confirm a Transaction by forwarding to Buyer by facsimile within three (3) Business Days after the Transaction is entered into a confirmation ("Confirmation") substantially in the form of Exhibit A. If Buyer objects to any term(s) of such Confirmation, Buyer shall notify Seller in writing of such objections within two (2) Business Days of Buyer's receipt thereof, failing which Buyer shall be deemed to have accepted the terms as sent. If Seller fails to send a Confirmation within three (3) Business Days after the Transaction is entered into, a Confirmation substantially in the form of Exhibit A, may be forwarded by Buyer to Seller. If Seller objects to any term(s) of such

Confirmation, Seller shall notify Buyer of such objections within two (2) Business Days of Seller's receipt thereof, failing which Seller shall be deemed to have accepted the terms as sent. If Seller and Buyer each send a Confirmation and neither Party objects to the other Party's Confirmation within two (2) Business Days of receipt, Seller's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation, unless (i) Seller's Confirmation was sent more than three (3) Business Days after the Transaction was entered into and (ii) Buyer's Confirmation was sent prior to Seller's Confirmation, in which case Buyer's Confirmation shall be deemed to be accepted and shall be the controlling Confirmation. Failure by either Party to send or either Party to return an executed Confirmation or any objection by either Party shall not invalidate the Transaction agreed to by the Parties.

2.4 Additional Confirmation Terms. If the Parties have elected on the Cover Sheet to make this Section 2.4 applicable to this Master Agreement, when a Confirmation contains provisions, other than those provisions relating to the commercial terms of the Transaction (e.g., price or special transmission conditions), which modify or supplement the general terms and conditions of this Master Agreement (e.g., arbitration provisions or additional representations and warranties), such provisions shall not be deemed to be accepted pursuant to Section 2.3 unless agreed to either orally or in writing by the Parties; provided that the foregoing shall not invalidate any Transaction agreed to by the Parties.

2.5 Recording. Unless a Party expressly objects to a Recording (defined below) at the beginning of a telephone conversation, each Party consents to the creation of a tape or electronic recording ("Recording") of all telephone conversations between the Parties to this Master Agreement, and that any such Recordings will be retained in confidence, secured from improper access, and may be submitted in evidence in any proceeding or action relating to this Agreement. Each Party waives any further notice of such monitoring or recording, and agrees to notify its officers and employees of such monitoring or recording and to obtain any necessary consent of such officers and employees. The Recording, and the terms and conditions described therein, if admissible, shall be the controlling evidence for the Parties' agreement with respect to a particular Transaction in the event a Confirmation is not fully executed (or deemed accepted) by both Parties. Upon full execution (or deemed acceptance) of a Confirmation, such Confirmation shall control in the event of any conflict with the terms of a Recording, or in the event of any conflict with the terms of this Master Agreement.

ARTICLE THREE: OBLIGATIONS AND DELIVERIES

3.1 Seller's and Buyer's Obligations. With respect to each Transaction, Seller shall sell and deliver, or cause to be delivered, and Buyer shall purchase and receive, or cause to be received, the Quantity of the Product at the Delivery Point, and Buyer shall pay Seller the Contract Price; provided, however, with respect to Options, the obligations set forth in the preceding sentence shall only arise if the Option Buyer exercises its Option in accordance with its terms. Seller shall be responsible for any costs or charges imposed on or associated with the Product or its delivery of the Product up to the Delivery Point. Buyer shall be responsible for any costs or charges imposed on or associated with the Product or its receipt at and from the Delivery Point.

3.2 Transmission and Scheduling. Seller shall arrange and be responsible for transmission service to the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers, as specified by the Parties in the Transaction, or in the absence thereof, in accordance with the practice of the Transmission Providers, to deliver the Product to the Delivery Point. Buyer shall arrange and be responsible for transmission service at and from the Delivery Point and shall Schedule or arrange for Scheduling services with its Transmission Providers to receive the Product at the Delivery Point.

3.3 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under the Transaction and such Party (the "Claiming Party") gives notice and details of the Force Majeure to the other Party as soon as practicable, then, unless the terms of the Product specify otherwise, the Claiming Party shall be excused from the performance of its obligations with respect to such Transaction (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure). The Claiming Party shall remedy the Force Majeure with all reasonable dispatch. The non-Claiming Party shall not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure.

ARTICLE FOUR: REMEDIES FOR FAILURE TO DELIVER/RECEIVE

4.1 Seller Failure. If Seller fails to schedule and/or deliver all or part of the Product pursuant to a Transaction, and such failure is not excused under the terms of the Product or by Buyer's failure to perform, then Seller shall pay Buyer, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

4.2 Buyer Failure. If Buyer fails to schedule and/or receive all or part of the Product pursuant to a Transaction and such failure is not excused under the terms of the Product or by Seller's failure to perform, then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred or, if "Accelerated Payment of Damages" is specified on the Cover Sheet, within five (5) Business Days of invoice receipt, an amount for such deficiency equal to the positive difference, if any, obtained by subtracting the Sales Price from the Contract Price. The invoice for such amount shall include a written statement explaining in reasonable detail the calculation of such amount.

ARTICLE FIVE: EVENTS OF DEFAULT; REMEDIES

5.1 Events of Default. An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

(a) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within three (3) Business Days after written notice;

(b) any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated;

(c) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default, and except for such Party's obligations to deliver or receive the Product, the exclusive remedy for which is provided in Article Four) if such failure is not remedied within three (3) Business Days after written notice;

(d) such Party becomes Bankrupt;

(e) the failure of such Party to satisfy the creditworthiness/collateral requirements agreed to pursuant to Article Eight hereof;

(f) such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party;

(g) if the applicable cross default section in the Cover Sheet is indicated for such Party, the occurrence and continuation of (i) a default, event of default or other similar condition or event in respect of such Party or any other party specified in the Cover Sheet for such Party under one or more agreements or instruments, individually or collectively, relating to indebtedness for borrowed money in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet), which results in such indebtedness becoming, or becoming capable at such time of being declared, immediately due and payable or (ii) a default by such Party or any other party specified in the Cover Sheet for such Party in making on the due date therefor one or more payments, individually or collectively, in an aggregate amount of not less than the applicable Cross Default Amount (as specified in the Cover Sheet);

(h) with respect to such Party's Guarantor, if any:

(i) if any representation or warranty made by a Guarantor in connection with this Agreement is false or misleading in any material respect when made or when deemed made or repeated;

(ii) the failure of a Guarantor to make any payment required or to perform any other material covenant or obligation in any guaranty made in connection with this Agreement and such failure shall not be remedied within three (3) Business Days after written notice;

(iii) a Guarantor becomes Bankrupt;

(iv) the failure of a Guarantor's guaranty to be in full force and effect for purposes of this Agreement (other than in accordance with its terms) prior to the satisfaction of all obligations of such Party under each Transaction to which such guaranty shall relate without the written consent of the other Party; or

(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of any guaranty.

5.2 Declaration of an Early Termination Date and Calculation of Settlement Amounts. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (the "Non-Defaulting Party") shall have the right (i) to designate a day, no earlier than the day such notice is effective and no later than 20 days after such notice is effective, as an early termination date ("Early Termination Date") to accelerate all amounts owing between the Parties and to liquidate and terminate all, but not less than all, Transactions (each referred to as a "Terminated Transaction") between the Parties, (ii) withhold any payments due to the Defaulting Party under this Agreement and (iii) suspend performance. The Non-Defaulting Party shall calculate, in a commercially reasonable manner, a Settlement Amount for each such Terminated Transaction as of the Early Termination Date (or, to the extent that in the reasonable opinion of the Non-Defaulting Party certain of such Terminated Transactions are commercially impracticable to liquidate and terminate or may not be liquidated and terminated under applicable law on the Early Termination Date, as soon thereafter as is reasonably practicable).

5.3 Net Out of Settlement Amounts. The Non-Defaulting Party shall aggregate all Settlement Amounts into a single amount by: netting out (a) all Settlement Amounts that are due to the Defaulting Party, plus, at the option of the Non-Defaulting Party, any cash or other form of security then available to the Non-Defaulting Party pursuant to Article Eight, plus any or all other amounts due to the Defaulting Party under this Agreement against (b) all Settlement Amounts that are due to the Non-Defaulting Party, plus any or all other amounts due to the Non-Defaulting Party under this Agreement, so that all such amounts shall be netted out to a single liquidated amount (the "Termination Payment") payable by one Party to the other. The Termination Payment shall be due to or due from the Non-Defaulting Party as appropriate.

5.4 Notice of Payment of Termination Payment. As soon as practicable after a liquidation, notice shall be given by the Non-Defaulting Party to the Defaulting Party of the amount of the Termination Payment and whether the Termination Payment is due to or due from the Non-Defaulting Party. The notice shall include a written statement explaining in reasonable detail the calculation of such amount. The Termination Payment shall be made by the Party that owes it within two (2) Business Days after such notice is effective.

5.5 Disputes With Respect to Termination Payment. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within two (2) Business Days of receipt of Non-Defaulting Party's

calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that if the Termination Payment is due from the Defaulting Party, the Defaulting Party shall first transfer Performance Assurance to the Non-Defaulting Party in an amount equal to the Termination Payment.

5.6 Closeout Setoffs.

Option A: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party to the Non-Defaulting Party under any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option B: After calculation of a Termination Payment in accordance with Section 5.3, if the Defaulting Party would be owed the Termination Payment, the Non-Defaulting Party shall be entitled, at its option and in its discretion, to (i) set off against such Termination Payment any amounts due and owing by the Defaulting Party or any of its Affiliates to the Non-Defaulting Party or any of its Affiliates under any other agreements, instruments or undertakings between the Defaulting Party or any of its Affiliates and the Non-Defaulting Party or any of its Affiliates and/or (ii) to the extent the Transactions are not yet liquidated in accordance with Section 5.2, withhold payment of the Termination Payment to the Defaulting Party. The remedy provided for in this Section shall be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of law, contract or otherwise).

Option C: Neither Option A nor B shall apply.

5.7 Suspension of Performance. Notwithstanding any other provision of this Master Agreement, if (a) an Event of Default or (b) a Potential Event of Default shall have occurred and be continuing, the Non-Defaulting Party, upon written notice to the Defaulting Party, shall have the right (i) to suspend performance under any or all Transactions; provided, however, in no event shall any such suspension continue for longer than ten (10) NERC Business Days with respect to any single Transaction unless an early Termination Date shall have been declared and notice thereof pursuant to Section 5.2 given, and (ii) to the extent an Event of Default shall have occurred and be continuing to exercise any remedy available at law or in equity.

ARTICLE SIX: PAYMENT AND NETTING

6.1 Billing Period. Unless otherwise specifically agreed upon by the Parties in a Transaction, the calendar month shall be the standard period for all payments under this

Agreement (other than Termination Payments and, if "Accelerated Payment of Damages" is specified by the Parties in the Cover Sheet, payments pursuant to Section 4.1 or 4.2 and Option premium payments pursuant to Section 6.7). As soon as practicable after the end of each month, each Party will render to the other Party an invoice for the payment obligations, if any, incurred hereunder during the preceding month.

6.2 Timeliness of Payment. Unless otherwise agreed by the Parties in a Transaction, all invoices under this Master Agreement shall be due and payable in accordance with each Party's invoice instructions on or before the later of the twentieth (20th) day of each month, or tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. Each Party will make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any amounts not paid by the due date will be deemed delinquent and will accrue interest at the Interest Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

6.3 Disputes and Adjustments of Invoices. A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice, rendered under this Agreement or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the objection given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment shall be made within two (2) Business Days of such resolution along with interest accrued at the Interest Rate from and including the due date to but excluding the date paid. Inadvertent overpayments shall be returned upon request or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Interest Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment. Any dispute with respect to an invoice is waived unless the other Party is notified in accordance with this Section 6.3 within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which performance of a Transaction occurred, the right to payment for such performance is waived.

6.4 Netting of Payments. The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing to each other on the same date pursuant to all Transactions through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Master Agreement, including any related damages calculated pursuant to Article Four (unless one of the Parties elects to accelerate payment of such amounts as permitted by Article Four), interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it.

6.5 Payment Obligation Absent Netting. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, including, but not limited to, any related damage amounts calculated pursuant to Article Four, interest, and payments or credits, that Party shall pay such sum in full when due.

6.6 Security. Unless the Party benefiting from Performance Assurance or a guaranty notifies the other Party in writing, and except in connection with a liquidation and termination in accordance with Article Five, all amounts netted pursuant to this Article Six shall not take into account or include any Performance Assurance or guaranty which may be in effect to secure a Party's performance under this Agreement.

6.7 Payment for Options. The premium amount for the purchase of an Option shall be paid within two (2) Business Days of receipt of an invoice from the Option Seller. Upon exercise of an Option, payment for the Product underlying such Option shall be due in accordance with Section 6.1.

6.8 Transaction Netting. If the Parties enter into one or more Transactions, which in conjunction with one or more other outstanding Transactions, constitute Offsetting Transactions, then all such Offsetting Transactions may by agreement of the Parties, be netted into a single Transaction under which:

(a) the Party obligated to deliver the greater amount of Energy will deliver the difference between the total amount it is obligated to deliver and the total amount to be delivered to it under the Offsetting Transactions, and

(b) the Party owing the greater aggregate payment will pay the net difference owed between the Parties.

Each single Transaction resulting under this Section shall be deemed part of the single, indivisible contractual arrangement between the parties, and once such resulting Transaction occurs, outstanding obligations under the Offsetting Transactions which are satisfied by such offset shall terminate.

ARTICLE SEVEN: LIMITATIONS

7.1 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN OR IN A TRANSACTION, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH

DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE EIGHT: CREDIT AND COLLATERAL REQUIREMENTS

8.1 Party A Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.1(a) is specified on the Cover Sheet, Section 8.l(a) Option C shall apply exclusively. If none of Sections 8.1(b), 8.1(c) or 8.1(d) are specified on the Cover Sheet, Section 8.1(b) shall apply exclusively.

(a) Financial Information.

Option A: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party B's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of Party B's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as Party B diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party A, Party B shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long

as the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party A may request from Party B the information specified in the Cover Sheet.

(b) Credit Assurances. If Party A has reasonable grounds to believe that Party B's creditworthiness or performance under this Agreement has become unsatisfactory, Party A will provide Party B with written notice requesting Performance Assurance in an amount determined by Party A in a commercially reasonable manner. Upon receipt of such notice Party B shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party A. In the event that Party B fails to provide such Performance Assurance, or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party A plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold, then Party A, on any Business Day, may request that Party B provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party B's Independent Amount, if any, exceeds the Party B Collateral Threshold (rounding upwards for any fractional amount to the next Party B Rounding Amount) ("Party B Performance Assurance"), less any Party B Performance Assurance already posted with Party A. Such Party B Performance Assurance shall be delivered to Party A within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party B, at its sole cost, may request that such Party B Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party B's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party B Rounding Amount). In the event that Party B fails to provide Party B Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.1(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party A as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party B to Party A, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party B, then Party A may require Party B to provide Performance Assurance in an amount determined by Party A in a commercially reasonable manner. In the event Party B shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party A within three (3) Business Days of receipt of notice, then an Event of Default shall be

deemed to have occurred and Party A will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party B shall deliver to Party A, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party A.

8.2 Party B Credit Protection. The applicable credit and collateral requirements shall be as specified on the Cover Sheet. If no option in Section 8.2(a) is specified on the Cover Sheet, Section 8.2(a) Option C shall apply exclusively. If none of Sections 8.2(b), 8.2(c) or 8.2(d) are specified on the Cover Sheet, Section 8.2(b) shall apply exclusively.

(a) Financial Information.

Option A: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of Party A's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of such Party's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as such Party diligently pursues the preparation, certification and delivery of the statements.

Option B: If requested by Party B, Party A shall deliver (i) within 120 days following the end of each fiscal year, a copy of the annual report containing audited consolidated financial statements for such fiscal year for the party(s) specified on the Cover Sheet and (ii) within 60 days after the end of each of its first three fiscal quarters of each fiscal year, a copy of quarterly report containing unaudited consolidated financial statements for such fiscal quarter for the party(s) specified on the Cover Sheet. In all cases the statements shall be for the most recent accounting period and shall be prepared in accordance with generally accepted accounting principles; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default so long as the relevant entity diligently pursues the preparation, certification and delivery of the statements.

Option C: Party B may request from Party A the information specified in the Cover Sheet.

(b) Credit Assurances. If Party B has reasonable grounds to believe that Party A's creditworthiness or performance under this Agreement has become unsatisfactory, Party B will provide Party A with written notice requesting Performance Assurance in an amount determined by Party B in a commercially reasonable manner. Upon receipt of such notice Party A shall have three (3) Business Days to remedy the situation by providing such Performance Assurance to Party B. In the event that Party A fails to provide such Performance Assurance, or

a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default under Article Five will be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(c) Collateral Threshold. If at any time and from time to time during the term of this Agreement (and notwithstanding whether an Event of Default has occurred), the Termination Payment that would be owed to Party B plus Party A's Independent Amount, if any, exceeds the Party A Collateral Threshold, then Party B, on any Business Day, may request that Party A provide Performance Assurance in an amount equal to the amount by which the Termination Payment plus Party A's Independent Amount, if any, exceeds the Party A Collateral Threshold (rounding upwards for any fractional amount to the next Party A Rounding Amount) ("Party A Performance Assurance"), less any Party A Performance Assurance already posted with Party B. Such Party A Performance Assurance shall be delivered to Party B within three (3) Business Days of the date of such request. On any Business Day (but no more frequently than weekly with respect to Letters of Credit and daily with respect to cash), Party A, at its sole cost, may request that such Party A Performance Assurance be reduced correspondingly to the amount of such excess Termination Payment plus Party A's Independent Amount, if any, (rounding upwards for any fractional amount to the next Party A Rounding Amount). In the event that Party A fails to provide Party A Performance Assurance pursuant to the terms of this Article Eight within three (3) Business Days, then an Event of Default under Article Five shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

For purposes of this Section 8.2(c), the calculation of the Termination Payment shall be calculated pursuant to Section 5.3 by Party B as if all outstanding Transactions had been liquidated, and in addition thereto, shall include all amounts owed but not yet paid by Party A to Party B, whether or not such amounts are due, for performance already provided pursuant to any and all Transactions.

(d) Downgrade Event. If at any time there shall occur a Downgrade Event in respect of Party A, then Party B may require Party A to provide Performance Assurance in an amount determined by Party B in a commercially reasonable manner. In the event Party A shall fail to provide such Performance Assurance or a guaranty or other credit assurance acceptable to Party B within three (3) Business Days of receipt of notice, then an Event of Default shall be deemed to have occurred and Party B will be entitled to the remedies set forth in Article Five of this Master Agreement.

(e) If specified on the Cover Sheet, Party A shall deliver to Party B, prior to or concurrently with the execution and delivery of this Master Agreement a guarantee in an amount not less than the Guarantee Amount specified on the Cover Sheet and in a form reasonably acceptable to Party B.

8.3 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent either or both Parties deliver Performance Assurance hereunder, each Party (a "Pledgor") hereby grants to the other Party (the "Secured Party") a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or

the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order to perfect the Secured Party's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, the Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in the possession of the Non-Defaulting Party or its agent; (iii) draw on any outstanding Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

ARTICLE NINE: GOVERNMENTAL CHARGES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Master Agreement in accordance with the intent of the parties to minimize all taxes , so long as neither Party is materially adversely affected by such efforts.

9.2 Governmental Charges. Seller shall pay or cause to be paid all taxes imposed by any government authority("Governmental Charges") on or with respect to the Product or a Transaction arising prior to the Delivery Point. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or a Transaction at and from the Delivery Point (other than ad valorem, franchise or income taxes which are related to the sale of the Product and are, therefore, the responsibility of the Seller). In the event Seller is required by law or regulation to remit or pay Governmental Charges which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Governmental Charges. If Buyer is required by law or regulation to remit or pay Governmental Charges which are Seller's responsibility hereunder, Buyer may deduct the amount of any such Governmental Charges from the sums due to Seller under Article 6 of this Agreement. Nothing shall obligate or cause a Party to pay or be liable to pay any Governmental Charges for which it is exempt under the law.

ARTICLE TEN: MISCELLANEOUS

10.1 Term of Master Agreement. The term of this Master Agreement shall commence on the Effective Date and shall remain in effect until terminated by either Party upon (thirty) 30 days' prior written notice; provided, however, that such termination shall not affect or excuse the performance of either Party under any provision of this Master Agreement that by its terms survives any such termination and, provided further, that this Master Agreement and any other documents executed and delivered hereunder shall remain in effect with respect to

the Transaction(s) entered into prior to the effective date of such termination until both Parties have fulfilled all of their obligations with respect to such Transaction(s), or such Transaction(s) that have been terminated under Section 5.2 of this Agreement.

10.2 Representations and Warranties. On the Effective Date and the date of entering into each Transaction, each Party represents and warrants to the other Party that:

(i) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(ii) it has all regulatory authorizations necessary for it to legally perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(iii) the execution, delivery and performance of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(iv) this Master Agreement, each Transaction (including any Confirmation accepted in accordance with Section 2.3), and each other document executed and delivered in accordance with this Master Agreement constitutes its legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses.

(v) it is not Bankrupt and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming Bankrupt;

(vi) there is not pending or, to its knowledge, threatened against it or any of its Affiliates any legal proceedings that could materially adversely affect its ability to perform its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(vii) no Event of Default or Potential Event of Default with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(viii) it is acting for its own account, has made its own independent decision to enter into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) and as to whether this Master Agreement and each such Transaction (including any Confirmation accepted in accordance with Section 2.3) is appropriate or

proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in so doing, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3);

(ix) it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code;

(x) it has entered into this Master Agreement and each Transaction (including any Confirmation accepted in accordance with Section 2.3) in connection with the conduct of its business and it has the capacity or ability to make or take delivery of all Products referred to in the Transaction to which it is a Party;

(xi) with respect to each Transaction (including any Confirmation accepted in accordance with Section 2.3) involving the purchase or sale of a Product or an Option, it is a producer, processor, commercial user or merchant handling the Product, and it is entering into such Transaction for purposes related to its business as such; and

(xii) the material economic terms of each Transaction are subject to individual negotiation by the Parties.

10.3 Title and Risk of Loss. Title to and risk of loss related to the Product shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer the Quantity of the Product free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any person arising prior to the Delivery Point.

10.4 Indemnity. Each Party shall indemnify, defend and hold harmless the other Party from and against any Claims arising from or out of any event, circumstance, act or incident first occurring or existing during the period when control and title to Product is vested in such Party as provided in Section 10.3. Each Party shall indemnify, defend and hold harmless the other Party against any Governmental Charges for which such Party is responsible under Article Nine.

10.5 Assignment. Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent may be withheld in the exercise of its sole discretion; provided, however, either Party may, without the consent of the other Party (and without relieving itself from liability hereunder), (i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign this Agreement to an affiliate of such Party which affiliate's creditworthiness is equal to or higher than that of such Party, or (iii) transfer or assign this Agreement to any person or entity succeeding to all or substantially all of the assets whose creditworthiness is equal to or higher than that of such

Party; provided, however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions hereof and so long as the transferring Party delivers such tax and enforceability assurance as the non-transferring Party may reasonably request.

10.6 Governing Law. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

10.7 Notices. All notices, requests, statements or payments shall be made as specified in the Cover Sheet. Notices (other than scheduling requests) shall, unless otherwise specified herein, be in writing and may be delivered by hand delivery, United States mail, overnight courier service or facsimile. Notice by facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a Business Day, and otherwise shall be effective at the close of business on the next Business Day. Notice by overnight United States mail or courier shall be effective on the next Business Day after it was sent. A Party may change its addresses by providing notice of same in accordance herewith.

10.8 General. This Master Agreement (including the exhibits, schedules and any written supplements hereto), the Party A Tariff, if any, the Party B Tariff, if any, any designated collateral, credit support or margin agreement or similar arrangement between the Parties and all Transactions (including any Confirmation accepted in accordance with Section 2.3) constitute the entire agreement between the Parties relating to the subject matter. Notwithstanding the foregoing, any collateral, credit support or margin agreement or similar arrangement between the Parties shall, upon designation by the Parties, be deemed part of this Agreement and shall be incorporated herein by reference. This Agreement shall be considered for all purposes as prepared through the joint efforts of the parties and shall not be construed against one party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof. Except to the extent herein provided for, no amendment or modification to this Master Agreement shall be enforceable unless reduced to writing and executed by both Parties. Each Party agrees if it seeks to amend any applicable wholesale power sales tariff during the term of this Agreement, such amendment will not in any way affect outstanding Transactions under this Agreement without the prior written consent of the other Party. Each Party further agrees that it will not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement. This Agreement shall not impart any rights enforceable by any third party (other than a permitted successor or assignee bound to this Agreement). Waiver by a Party of any default by the other Party shall not be construed as a waiver of any other default. Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change (individually or collectively, such events referred to as "Regulatory Event") will not otherwise affect the remaining lawful obligations that arise under this Agreement; and provided, further, that if a Regulatory Event occurs, the Parties shall use their best efforts to reform this Agreement in order to give effect to the original intention of the Parties. The term

"including" when used in this Agreement shall be by way of example only and shall not be considered in any way to be in limitation. The headings used herein are for convenience and reference purposes only. All indemnity and audit rights shall survive the termination of this Agreement for twelve (12) months. This Agreement shall be binding on each Party's successors and permitted assigns.

10.9 Audit. Each Party has the right, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Master Agreement. If requested, a Party shall provide to the other Party statements evidencing the Quantity delivered at the Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until paid; provided, however, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twelve (12) months from the rendition thereof, and thereafter any objection shall be deemed waived.

10.10 Forward Contract. The Parties acknowledge and agree that all Transactions constitute "forward contracts" within the meaning of the United States Bankruptcy Code.

10.11 Confidentiality. If the Parties have elected on the Cover Sheet to make this Section 10.11 applicable to this Master Agreement, neither Party shall disclose the terms or conditions of a Transaction under this Master Agreement to a third party (other than the Party's employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area or independent system operator rule or in connection with any court or regulatory proceeding; provided, however, each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with, this confidentiality obligation.

SCHEDULE P: PRODUCTS AND RELATED DEFINITIONS

"Ancillary Services" means any of the services identified by a Transmission Provider in its transmission tariff as "ancillary services" including, but not limited to, regulation and frequency response, energy imbalance, operating reserve-spinning and operating reserve-supplemental, as may be specified in the Transaction.

"Capacity" has the meaning specified in the Transaction.

"Energy" means three-phase, 60-cycle alternating current electric energy, expressed in megawatt hours.

"Firm (LD)" means, with respect to a Transaction, that either Party shall be relieved of its obligations to sell and deliver or purchase and receive without liability only to the extent that, and for the period during which, such performance is prevented by Force Majeure. In the absence of Force Majeure, the Party to which performance is owed shall be entitled to receive from the Party which failed to deliver/receive an amount determined pursuant to Article Four.

"Firm Transmission Contingent - Contract Path" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product in the case of the Seller from the generation source to the Delivery Point or in the case of the Buyer from the Delivery Point to the ultimate sink, and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This contingency shall excuse performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary.

"Firm Transmission Contingent - Delivery Point" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission to the Delivery Point (in the case of Seller) or from the Delivery Point (in the case of Buyer) for such Transaction is interrupted or curtailed and (i) such Party has provided for firm transmission with the transmission provider(s) for the Product, in the case of the Seller, to be delivered to the Delivery Point or, in the case of Buyer, to be received at the Delivery Point and (ii) such interruption or curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the applicable transmission provider's tariff. This transmission contingency excuses performance for the duration of the interruption or curtailment, notwithstanding the provisions of the definition of "Force Majeure" in Section 1.23 to the contrary. Interruptions or curtailments of transmission other than the transmission either immediately to or from the Delivery Point shall not excuse performance

"Firm (No Force Majeure)" means, with respect to a Transaction, that if either Party fails to perform its obligation to sell and deliver or purchase and receive the Product, the Party to which performance is owed shall be entitled to receive from the Party which failed to perform an

amount determined pursuant to Article Four. Force Majeure shall not excuse performance of a Firm (No Force Majeure) Transaction.

"Into _____ (the "Receiving Transmission Provider"), Seller's Daily Choice" means that, in accordance with the provisions set forth below, (1) the Product shall be scheduled and delivered to an interconnection or interface ("Interface") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which Interface, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area; and (2) Seller has the right on a daily prescheduled basis to designate the Interface where the Product shall be delivered. An "Into" Product shall be subject to the following provisions:

1. Prescheduling and Notification. Subject to the provisions of Section 6, not later than the prescheduling deadline of 11:00 a.m. CPT on the Business Day before the next delivery day or as otherwise agreed to by Buyer and Seller, Seller shall notify Buyer ("Seller's Notification") of Seller's immediate upstream counterparty and the Interface (the "Designated Interface") where Seller shall deliver the Product for the next delivery day, and Buyer shall notify Seller of Buyer's immediate downstream counterparty.

2. Availability of "Firm Transmission" to Buyer at Designated Interface; "Timely Request for Transmission," "ADI" and "Available Transmission." In determining availability to Buyer of next-day firm transmission ("Firm Transmission") from the Designated Interface, a "Timely Request for Transmission" shall mean a properly completed request for Firm Transmission made by Buyer in accordance with the controlling tariff procedures, which request shall be submitted to the Receiving Transmission Provider no later than 30 minutes after delivery of Seller's Notification, provided, however, if the Receiving Transmission Provider is not accepting requests for Firm Transmission at the time of Seller's Notification, then such request by Buyer shall be made within 30 minutes of the time when the Receiving Transmission Provider first opens thereafter for purposes of accepting requests for Firm Transmission.

Pursuant to the terms hereof, delivery of the Product may under certain circumstances be redesignated to occur at an Interface other than the Designated Interface (any such alternate designated interface, an "ADI") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which ADI, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area using either firm or non-firm transmission, as available on a day-ahead or hourly basis (individually or collectively referred to as "Available Transmission") within the Receiving Transmission Provider's transmission system.

3. Rights of Buyer and Seller Depending Upon Availability of/Timely Request for Firm Transmission.

A. Timely Request for Firm Transmission made by Buyer, Accepted by the Receiving Transmission Provider and Purchased by Buyer. If a Timely Request for Firm Transmission is made by Buyer and is accepted by the Receiving Transmission Provider

and Buyer purchases such Firm Transmission, then Seller shall deliver and Buyer shall receive the Product at the Designated Interface.

i. If the Firm Transmission purchased by Buyer within the Receiving Transmission Provider's transmission system from the Designated Interface ceases to be available to Buyer for any reason, or if Seller is unable to deliver the Product at the Designated Interface for any reason except Buyer's non-performance, then at Seller's choice from among the following, Seller shall: (a) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, require Buyer to purchase such Firm Transmission from such ADI, and schedule and deliver the affected portion of the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, or (b) require Buyer to purchase non-firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by Seller, or (c) to the extent firm transmission is available on an hourly basis, require Buyer to purchase firm transmission, and schedule and deliver the affected portion of the Product on the basis of Buyer's purchase of such hourly firm transmission from the Designated Interface or an ADI designated by Seller.

ii. If the Available Transmission utilized by Buyer as required by Seller pursuant to Section 3A(i) ceases to be available to Buyer for any reason, then Seller shall again have those alternatives stated in Section 3A(i) in order to satisfy its obligations.

iii. Seller's obligation to schedule and deliver the Product at an ADI is subject to Buyer's obligation referenced in Section 4B to cooperate reasonably therewith. If Buyer and Seller cannot complete the scheduling and/or delivery at an ADI, then Buyer shall be deemed to have satisfied its receipt obligations to Seller and Seller shall be deemed to have failed its delivery obligations to Buyer, and Seller shall be liable to Buyer for amounts determined pursuant to Article Four.

iv. In each instance in which Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI pursuant to Sections 3A(i) or (ii), and Firm Transmission had been purchased by both Seller and Buyer into and within the Receiving Transmission Provider's transmission system as to the scheduled delivery which could not be completed as a result of the interruption or curtailment of such Firm Transmission, Buyer and Seller shall bear their respective transmission expenses and/or associated congestion charges incurred in connection with efforts to complete delivery by such alternative scheduling and delivery arrangements. In any instance except as set forth in the immediately preceding sentence, Buyer and Seller must make alternative scheduling arrangements for delivery at the Designated Interface or an ADI under Sections 3A(i) or (ii), Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with such alternative scheduling arrangements.

B. Timely Request for Firm Transmission Made by Buyer but Rejected by the Receiving Transmission Provider. If Buyer's Timely Request for Firm Transmission is rejected by the Receiving Transmission Provider because of unavailability of Firm Transmission from the Designated Interface, then Buyer shall notify Seller within 15 minutes after receipt of the Receiving Transmission Provider's notice of rejection ("Buyer's Rejection Notice"). If Buyer timely notifies Seller of such unavailability of Firm Transmission from the Designated Interface, then Seller shall be obligated either (1) to the extent Firm Transmission is available to Buyer from an ADI on a day-ahead basis, to require Buyer to purchase (at Buyer's own expense) such Firm Transmission from such ADI and schedule and deliver the Product to such ADI on the basis of Buyer's purchase of Firm Transmission, and thereafter the provisions in Section 3A shall apply, or (2) to require Buyer to purchase (at Buyer's own expense) non-firm transmission, and schedule and deliver the Product on the basis of Buyer's purchase of non-firm transmission from the Designated Interface or an ADI designated by the Seller, in which case Seller shall bear the risk of interruption or curtailment of the non-firm transmission; provided, however, that if the non-firm transmission is interrupted or curtailed or if Seller is unable to deliver the Product for any reason, Seller shall have the right to schedule and deliver the Product to another ADI in order to satisfy its delivery obligations, in which case Seller shall be responsible for any additional transmission purchases and/or associated congestion charges incurred by Buyer in connection with Seller's inability to deliver the Product as originally prescheduled. If Buyer fails to timely notify Seller of the unavailability of Firm Transmission, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface, and the provisions of Section 3D shall apply.

C. Timely Request for Firm Transmission Made by Buyer, Accepted by the Receiving Transmission Provider and not Purchased by Buyer. If Buyer's Timely Request for Firm Transmission is accepted by the Receiving Transmission Provider but Buyer elects to purchase non-firm transmission rather than Firm Transmission to take delivery of the Product, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

D. No Timely Request for Firm Transmission Made by Buyer, or Buyer Fails to Timely Send Buyer's Rejection Notice. If Buyer fails to make a Timely Request for Firm Transmission or Buyer fails to timely deliver Buyer's Rejection Notice, then Buyer shall bear the risk of interruption or curtailment of transmission from the Designated Interface. In such circumstances, if Seller's delivery is interrupted as a result of transmission relied upon by Buyer from the Designated Interface, then Seller shall be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for amounts determined pursuant to Article Four.

4. Transmission.

A. Seller's Responsibilities. Seller shall be responsible for transmission required to deliver the Product to the Designated Interface or ADI, as the case may be. It is expressly agreed that Seller is not required to utilize Firm Transmission for its delivery obligations hereunder, and Seller shall bear the risk of utilizing non-firm transmission. If Seller's scheduled delivery to Buyer is interrupted as a result of Buyer's attempted transmission of the Product beyond the Receiving Transmission Provider's system border, then Seller will be deemed to have satisfied its delivery obligations to Buyer, Buyer shall be deemed to have failed to receive the Product and Buyer shall be liable to Seller for damages pursuant to Article Four.

B. Buyer's Responsibilities. Buyer shall be responsible for transmission required to receive and transmit the Product at and from the Designated Interface or ADI, as the case may be, and except as specifically provided in Section 3A and 3B, shall be responsible for any costs associated with transmission therefrom. If Seller is attempting to complete the designation of an ADI as a result of Seller's rights and obligations hereunder, Buyer shall co-operate reasonably with Seller in order to effect such alternate designation.

5. Force Majeure. An "Into" Product shall be subject to the "Force Majeure" provisions in Section 1.23.

6. Multiple Parties in Delivery Chain Involving a Designated Interface. Seller and Buyer recognize that there may be multiple parties involved in the delivery and receipt of the Product at the Designated Interface or ADI to the extent that (1) Seller may be purchasing the Product from a succession of other sellers ("Other Sellers"), the first of which Other Sellers shall be causing the Product to be generated from a source ("Source Seller") and/or (2) Buyer may be selling the Product to a succession of other buyers ("Other Buyers"), the last of which Other Buyers shall be using the Product to serve its energy needs ("Sink Buyer"). Seller and Buyer further recognize that in certain Transactions neither Seller nor Buyer may originate the decision as to either (a) the original identification of the Designated Interface or ADI (which designation may be made by the Source Seller) or (b) the Timely Request for Firm Transmission or the purchase of other Available Transmission (which request may be made by the Sink Buyer). Accordingly, Seller and Buyer agree as follows:

A. If Seller is not the Source Seller, then Seller shall notify Buyer of the Designated Interface promptly after Seller is notified thereof by the Other Seller with whom Seller has a contractual relationship, but in no event may such designation of the Designated Interface be later than the prescheduling deadline pertaining to the Transaction between Buyer and Seller pursuant to Section 1.

B. If Buyer is not the Sink Buyer, then Buyer shall notify the Other Buyer with whom Buyer has a contractual relationship of the Designated Interface promptly after Seller notifies Buyer thereof, with the intent being that the party bearing actual responsibility to secure transmission shall have up to 30 minutes after receipt of the Designated Interface to submit its Timely Request for Firm Transmission.

C. Seller and Buyer each agree that any other communications or actions required to be given or made in connection with this "Into Product" (including without limitation, information relating to an ADI) shall be made or taken promptly after receipt of the relevant information from the Other Sellers and Other Buyers, as the case may be.

D. Seller and Buyer each agree that in certain Transactions time is of the essence and it may be desirable to provide necessary information to Other Sellers and Other Buyers in order to complete the scheduling and delivery of the Product. Accordingly, Seller and Buyer agree that each has the right, but not the obligation, to provide information at its own risk to Other Sellers and Other Buyers, as the case may be, in order to effect the prescheduling, scheduling and delivery of the Product

"Native Load" means the demand imposed on an electric utility or an entity by the requirements of retail customers located within a franchised service territory that the electric utility or entity has statutory obligation to serve.

"Non-Firm" means, with respect to a Transaction, that delivery or receipt of the Product may be interrupted for any reason or for no reason, without liability on the part of either Party.

"System Firm" means that the Product will be supplied from the owned or controlled generation or pre-existing purchased power assets of the system specified in the Transaction (the "System") with non-firm transmission to and from the Delivery Point, unless a different Transmission Contingency is specified in a Transaction. Seller's failure to deliver shall be excused: (i) by an event or circumstance which prevents Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, which is not within the reasonable control of, or the result of the negligence of, the Seller; (ii) by Buyer's failure to perform; (iii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on, the System; (iv) to the extent the System or the control area or reliability council within which the System operates declares an emergency condition, as determined in the system's, or the control area's, or reliability council's reasonable judgment; or (v) by the interruption or curtailment of transmission to the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Seller's performance. Buyer's failure to receive shall be excused (i) by Force Majeure; (ii) by Seller's failure to perform, or (iii) by the interruption or curtailment of transmission from the Delivery Point or by the occurrence of any Transmission Contingency specified in a Transaction as excusing Buyer's performance. In any of such events, neither party shall be liable to the other for any damages, including any amounts determined pursuant to Article Four.

"Transmission Contingent" means, with respect to a Transaction, that the performance of either Seller or Buyer (as specified in the Transaction) shall be excused, and no damages shall be payable including any amounts determined pursuant to Article Four, if the transmission for such Transaction is unavailable or interrupted or curtailed for any reason, at any time, anywhere from the Seller's proposed generating source to the Buyer's proposed ultimate sink, regardless of whether transmission, if any, that such Party is attempting to secure and/or has purchased for the Product is firm or non-firm. If the transmission (whether firm or non-firm) that Seller or Buyer is attempting to secure is from source to sink is unavailable, this contingency excuses performance for the entire Transaction. If the transmission (whether firm or non-firm) that Seller

or Buyer has secured from source to sink is interrupted or curtailed for any reason, this contingency excuses performance for the duration of the interruption or curtailment notwithstanding the provisions of the definition of "Force Majeure" in Article 1.23 to the contrary.

"Unit Firm" means, with respect to a Transaction, that the Product subject to the Transaction is intended to be supplied from a generation asset or assets specified in the Transaction. Seller's failure to deliver under a "Unit Firm" Transaction shall be excused: (i) if the specified generation asset(s) are unavailable as a result of a Forced Outage (as defined in the NERC Generating Unit Availability Data System (GADS) Forced Outage reporting guidelines) or (ii) by an event or circumstance that affects the specified generation asset(s) so as to prevent Seller from performing its obligations, which event or circumstance was not anticipated as of the date the Transaction was agreed to, and which is not within the reasonable control of, or the result of the negligence of, the Seller or (iii) by Buyer's failure to perform. In any of such events, Seller shall not be liable to Buyer for any damages, including any amounts determined pursuant to Article Four.

EXHIBIT A

MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER

This confirmation letter shall confirm the Transaction agreed to on _____, ___ between _____ ("Party A") and _____ ("Party B") regarding the sale/purchase of the Product under the terms and conditions as follows:

Seller: _____

Buyer: _____

Product:

[] Into _____, Seller's Daily Choice

[] Firm (LD)

[] Firm (No Force Majeure)

[] System Firm

(Specify System: _____)

[] Unit Firm

(Specify Unit(s): _____)

[] Other _____

[] Transmission Contingency (If not marked, no transmission contingency)

[]	FT-Contract Path Contingency	[]	Seller	[]	Buyer
[]	FT-Delivery Point Contingency	[]	Seller	[]	Buyer
[]	Transmission Contingent	[]	Seller	[]	Buyer
[]	Other transmission contingency				

(Specify: _____)

Contract Quantity: _____

Delivery Point: _____

Contract Price:

Energy Price: _____

Other Charges: _____

Confirmation Letter
Page 2

Delivery Period: _____

Special Conditions: _____

Scheduling: _____

Option Buyer: _____

Option Seller: _____

Type of Option: _____

Strike Price: _____

Premium: _____

Exercise Period: _____

This confirmation letter is being provided pursuant to and in accordance with the Master Power Purchase and Sale Agreement dated _____ (the "Master Agreement") between Party A and Party B, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

[Party A]	[Party B]
Name: _____	Name: _____
Title: _____	Title: _____
Phone No: _____	Phone No: _____
Fax: _____	Fax: _____

In The Matter Of The Application Of Public Service Company Of Colorado For Approval Of Its 2011 Electric Resource Plan	**)** **)** **)** **)**	**Second Set of Discovery Request From City of Boulder Served on Public Service Company**
Docket Nos. 11A-869E, 12A-782E, and 12A-785E Consolidated	**)** **)**	**August 23, 2012**

DISCOVERY REQUEST NO. BLDR2-3:

Please provide all documents that show historical demand and capacity for the City for the years 2005 through 2011.

OBJECTION:

Public Service objects to this question on the grounds of relevance. Public Service acquires power supply to meet its entire system load. This question appears to be directed toward obtaining information with respect to Boulder's municipalization investigation, which is not an appropriate inquiry in this docket.

Sponsor: Paula Connelly **Response Date**: August 27, 2012

RESPONSE:

Without waiving our objection, see Attachment Bldr2-3.A1. This document estimates the City of Boulder's historical coincident demand from Company billing records.

Sponsor: Jannell Marks **Response Date**: August 29, 2012

Colorado PUC E-Filings System

In The Matter Of The Application Of Public Service Company Of Colorado For Approval Of Its 2011 Electric Resource Plan	**)** **)** **)** **)**	**Second Set of Discovery Request From City of Boulder Served on Public Service Company**
Docket Nos. 11A-869E, 12A-782E, and 12A-785E Consolidated	**)** **)**	**August 23, 2012**

DISCOVERY REQUEST NO. BLDR2-4:

Please provide all documents that show projected load and capacity for the City for the years 2012 through 2018.

OBJECTION:

Public Service objects to this question on the grounds of relevance. Public Service acquires power supply to meet its entire system load. This question appears to be directed toward obtaining information with respect to Boulder's municipalization investigation, which is not an appropriate inquiry in this docket.

Sponsor: Paula Connelly **Response Date**: August 27, 2012

RESPONSE:

Without waiving our objection, see Attachment Bldr2-3.A1.

Sponsor: Jannell Marks **Response Date**: August 29, 2012

ATTACHMENT Bldr2-3 A1_FINAL_8-29-12

Estimated Boulder Peak Demand Forecast - MW

	Estimated Boulder Retail Demand MW	%chg
2005	190	
2006	237	24.6%
2007	218	-8.0%
2008	231	6.1%
2009	235	1.9%
2010	240	1.9%
2011	242	0.7%
2012	245	1.4%
2013	247	0.8%
2014	249	1.0%
2015	251	0.9%
2016	254	0.9%
2017	255	0.7%
2018	257	0.6%
2019	258	0.5%
2020	259	0.5%
2021	261	0.4%
2022	262	0.5%
2023	263	0.5%
2024	264	0.5%
2025	266	0.5%
2026	267	0.4%
2027	268	0.4%
2028	269	0.4%
2029	269	0.3%
2030	270	0.3%
2031	271	0.3%
2032	272	0.3%
2033	272	0.2%
2034	273	0.2%
2035	274	0.2%

In The Matter Of The Application Of Public Service Company Of Colorado For Approval Of Its 2011 Electric Resource Plan	**)**	**Third Set of Discovery Request From City of Boulder Served on Public Service Company**
Docket Nos. 11A-869E, 12A-782E, and 12A-785E Consolidated	**)**	**September 10, 2012**

DISCOVERY REQUEST NO. BLDR3-1:

With regard to the Public Service response to Boulder discovery request BLDR 2-3 sponsored by Jannell Marks, wherein Ms. Marks states that the attached document "estimates the City of Boulder's historical coincident demand from Company billing records," please:

a. Explain what is meant by "historical coincident demand."
b. Explain the method by which the "historical coincident demand from the Company's billing records" was used to extrapolate information regarding projected energy consumption in MW for the city of Boulder from 2011 to 2035, which is found in Attachment Bldr2-3.A1.

OBJECTION:

Public Service objects to this question on the grounds of relevance. Public Service acquires power supply to meet its entire system load. This question appears to be directed toward obtaining information with respect to Boulder's municipalization investigation, which is not an appropriate inquiry in this docket.

Sponsor: Paula Connelly **Response Date**: September 17, 2012

RESPONSE:

Without waiving our objection, Public Service states:

a. Historical coincident demand is the Company's estimate of the City of Boulder's contribution to the PSCo system peak demand for the time period 2005-2010. The estimate is derived by applying load factors, loss factors, and hours in each month to monthly actual MWh retail sales by rate class for the City of Boulder service area obtained from the Company's billing system, using this formula:

Peak Demand = (MWh Sales*Loss Factor)/(Load Factor * Hours)

In The Matter Of The Application Of	**)**	**Third Set of Discovery Request**
Public Service Company Of Colorado	**)**	**From City of Boulder**
For Approval Of Its 2011 Electric	**)**	**Served on Public Service Company**
Resource Plan	**)**	
Docket Nos. 11A-869E, 12A-782E, and	**)**	
12A-785E Consolidated	**)**	**September 10, 2012**

DISCOVERY REQUEST NO. BLDR3-1 CONTINUED:

b. Monthly peak demands are calculated by applying load factors, loss factors, and hours in each month, to forecasted MWh sales using the formula provided in part a. The forecasted MWh sales were developed by rate class based on regression models.

Sponsor: Jannell Marks

Response Date: September 17, 2012

In The Matter Of The Application Of Public Service Company Of Colorado For Approval Of Its 2011 Electric Resource Plan	**)**	**Third Set of Discovery Request From City of Boulder Served on Public Service Company**
Docket Nos. 11A-869E, 12A-782E, and 12A-785E Consolidated	**)**	**September 10, 2012**

DISCOVERY REQUEST NO. BLDR3-2:

With regard to Attachment Bldr2-3.A1 (the "Attachment"), included with the Public Service response to BLDR 2-3 that was sponsored by Public Service witness Jannell Marks on August 29, 2012, please respond to the following questions:

a. When was the Attachment prepared?
b. By whom was the Attachment prepared?
c. What data was used to prepare the Attachment?
d. What is the source of the information included in the Attachment?
e. Please provide a copy of all work papers or analyses used in the creation of the Attachment.

OBJECTION:

Public Service objects to this question on the grounds of relevance. Public Service acquires power supply to meet its entire system load. This question appears to be directed toward obtaining information with respect to Boulder's municipalization investigation, which is not an appropriate inquiry in this docket.

Sponsor: Paula Connelly **Response Date**: September 17, 2012

RESPONSE:

Without waiving our objection, Public Service states:

a. The Attachment was prepared on August 28, 2012 based on analysis conducted in May 2011.
b. The Attachment was prepared by Luke Jaramillo, Senior Energy Forecasting Analyst.
c. The peak demand presented in the attachment was calculated based on historical retail MWh sales for the City of Boulder service area, calculated retail load factors by rate class for the PSCo system, and PSCo system loss factors by voltage level.

In The Matter Of The Application Of	**)**	**Third Set of Discovery Request**
Public Service Company Of Colorado	**)**	**From City of Boulder**
For Approval Of Its 2011 Electric	**)**	**Served on Public Service Company**
Resource Plan	**)**	
Docket Nos. 11A-869E, 12A-782E, and	**)**	
12A-785E Consolidated	**)**	**September 10, 2012**

DISCOVERY REQUEST NO. BLDR3-2 CONTINUED:

d. The source of the historical retail MWh sales is the Company's billing system. The forecast of retail MWh sales was developed by the Company using regression models. The PSCo system coincident peak load factors are calculated from PSCo load research sample data. The loss factors come from a 2006 PSCo loss study.

e. See Attachment BLDR3-2.A1.

Attachments:
Attachment BLDR3-2.A1

Sponsor: Jannell Marks Response Date: September 17, 2012

Boulder Peak Demand Forecast (MW)

Year Month	Residential MWh	Commercial no demand MWh	Secondary General MWh	Primary General MWh	Transmission General MWh	Street Lighting MWh	Total Retail MWh	Hours
Jan-05	24,607	6,980	42,164	31,749	156	469	106,124	744
Feb-05	21,506	6,421	35,687	27,989	153	415	92,171	672
Mar-05	19,695	6,249	39,570	31,024	153	411	97,102	744
Apr-05	18,352	6,266	38,356	28,328	127	372	91,801	720
May-05	19,105	6,548	40,166	27,368	111	342	93,641	744
Jun-05	16,942	6,452	43,822	28,086	110	332	95,744	720
Jul-05	22,227	6,524	40,114	26,733	106	345	96,050	744
Aug-05	21,426	6,129	35,387	40,028	101	370	103,440	744
Sep-05	17,428	12,248	50,148	28,417	128	(635)	107,735	720
Oct-05	19,909	3,829	50,169	37,222	0	345	111,473	744
Nov-05	20,764	7,097	45,594	28,999	13,733	352	116,540	720
Dec-05	25,041	7,376	43,982	14,918	13,740	378	105,434	744
Jan-06	23,830	7,540	39,930	12,829	14,157	370	98,657	744
Feb-06	20,584	5,432	36,842	9,061	13,351	316	85,587	672
Mar-06	19,343	6,622	39,773	14,392	15,345	313	95,788	744
Apr-06	20,032	7,024	39,680	23,049	14,720	272	104,777	720
May-06	17,174	6,611	41,519	46,706	15,569	242	127,822	744
Jun-06	17,784	6,335	42,231	17,916	15,719	219	100,205	720
Jul-06	24,465	7,960	51,515	20,151	16,165	257	120,512	744
Aug-06	20,696	7,054	44,923	16,547	16,491	269	105,980	744
Sep-06	19,598	7,107	46,916	20,034	15,317	292	109,263	720
Oct-06	18,188	6,261	43,455	12,772	15,776	334	96,786	744
Nov-06	21,342	6,502	43,058	29,858	14,708	355	115,822	720
Dec-06	27,751	7,338	47,997	25,774	15,160	382	124,403	744
Jan-07	23,805	6,460	38,698	20,365	15,292	374	104,994	744
Feb-07	22,395	6,420	39,679	19,671	13,809	320	102,295	672
Mar-07	21,417	6,436	41,269	22,034	15,781	317	107,253	744
Apr-07	19,155	6,380	40,969	21,124	14,959	275	102,863	720
May-07	18,142	6,070	41,602	21,997	15,562	244	103,617	744
Jun-07	17,795	6,338	46,242	17,068	15,332	234	103,008	720
Jul-07	22,803	7,378	50,497	13,185	15,934	248	110,045	744
Aug-07	21,552	7,186	47,066	14,425	16,107	330	106,666	744
Sep-07	22,846	7,457	48,822	24,828	15,288	353	119,594	720
Oct-07	17,754	6,497	45,091	23,037	16,355	395	109,129	744
Nov-07	20,855	6,307	43,657	22,113	15,574	414	108,920	720
Dec-07	26,795	7,375	46,042	23,330	15,180	441	119,164	744
Jan-08	23,622	6,404	40,010	19,924	16,184	433	106,576	744
Feb-08	22,055	6,465	39,440	10,453	15,296	379	94,088	696
Mar-08	22,274	6,977	44,281	12,825	16,756	375	103,489	744
Apr-08	18,305	6,151	39,872	18,683	16,784	334	100,129	720
May-08	18,588	6,251	42,877	22,740	16,803	303	107,563	744
Jun-08	17,776	6,474	45,305	22,304	16,993	293	109,145	720
Jul-08	20,787	7,202	50,705	21,940	17,987	308	118,929	744
Aug-08	23,002	7,180	45,689	23,358	17,758	334	117,321	744
Sep-08	19,727	7,246	50,810	24,579	16,821	357	119,540	720
Oct-08	17,497	6,506	44,569	16,421	17,710	400	103,102	744
Nov-08	21,131	6,204	43,018	25,399	16,825	419	112,995	720
Dec-08	25,034	7,135	46,159	20,660	16,367	446	115,801	744
Jan-09	24,850	6,727	41,660	20,500	16,772	438	110,947	744
Feb-09	21,009	6,179	40,665	21,079	14,941	382	104,256	672
Mar-09	19,509	6,132	40,956	20,473	16,474	379	103,923	744
Apr-09	18,688	5,642	41,111	21,154	16,721	337	103,652	720
May-09	19,869	6,413	46,091	22,700	16,684	307	112,064	744
Jun-09	16,446	5,843	45,285	13,133	16,166	296	97,170	720
Jul-09	20,408	6,642	49,638	27,249	18,038	310	122,285	744
Aug-09	20,900	6,958	52,049	22,971	17,747	335	120,959	744
Sep-09	18,252	6,358	45,696	22,942	17,315	358	110,921	720
Oct-09	18,722	6,215	44,985	22,091	17,562	403	109,978	744
Nov-09	23,589	6,400	43,098	22,544	17,353	421	113,406	720
Dec-09	24,356	6,400	45,373	21,326	18,023	449	115,927	744
Jan-10	25,884	6,778	43,717	19,402	17,944	441	114,166	744
Feb-10	20,974	5,985	40,727	23,202	15,845	384	107,118	672
Mar-10	20,286	5,954	40,772	19,792	18,277	381	105,461	744
Apr-10	18,112	5,695	40,581	20,290	18,181	339	103,198	720
May-10	19,136	6,252	43,884	22,995	18,602	307	111,175	744
Jun-10	17,139	5,936	46,013	19,848	18,727	296	107,959	720
Jul-10	22,034	7,118	52,593	21,986	19,593	311	123,634	744
Aug-10	21,820	7,172	51,033	23,259	19,783	335	123,403	744

Sep-10	18,604	6,839	44,866	22,023	18,544	360	111,237	720
Oct-10	18,982	7,153	48,098	24,146	18,977	385	117,741	744
Nov-10	19,980	6,283	43,949	23,058	17,744	424	111,437	720
Dec-10	25,175	7,274	45,128	21,536	17,550	453	117,116	744
Jan-11	22,956	6,328	42,361	20,481	18,339	445	110,909	744
Feb-11	22,326	6,750	41,845	21,226	18,513	389	111,049	672
Mar-11	19,809	6,214	42,423	19,764	16,417	381	105,008	744
Apr-11	19,409	5,867	41,509	22,171	18,531	338	107,826	720
May-11	18,826	6,321	44,267	21,087	18,612	305	109,418	744
Jun-11	17,266	6,158	47,076	19,692	18,817	301	109,309	720
Jul-11	22,112	7,293	53,541	22,368	18,607	315	124,236	744
Aug-11	21,585	7,217	51,709	22,428	20,067	339	123,346	744
Sep-11	18,823	6,893	46,459	22,540	20,013	362	115,089	720
Oct-11	19,334	6,440	45,864	23,333	19,122	427	114,520	744
Nov-11	21,099	6,393	45,083	24,237	19,485	420	116,717	720
Dec-11	24,635	7,224	46,885	23,357	18,716	452	121,269	744
Jan-12	23,135	6,370	43,200	22,652	18,547	444	114,348	744
Feb-12	22,497	6,491	42,416	21,939	18,723	389	112,455	696
Mar-12	19,926	6,278	43,135	21,450	16,604	382	107,776	744
Apr-12	19,487	5,889	42,421	22,612	18,742	341	109,491	720
May-12	18,851	6,333	42,869	21,211	18,823	306	108,393	744
Jun-12	17,289	6,196	47,860	21,057	19,030	306	111,738	720
Jul-12	22,385	7,374	54,458	22,559	18,818	319	125,913	744
Aug-12	21,651	7,251	52,586	21,391	20,295	342	123,516	744
Sep-12	18,879	6,919	47,258	23,137	20,240	364	116,798	720
Oct-12	19,462	6,475	46,732	22,224	19,339	429	114,662	744
Nov-12	21,148	6,423	45,866	24,513	19,706	424	118,080	720
Dec-12	24,762	7,289	47,504	25,050	18,928	453	123,986	744
Jan-13	23,294	6,379	43,995	23,101	18,547	445	115,761	744
Feb-13	22,544	6,508	42,743	23,605	18,723	389	114,512	672
Mar-13	20,145	6,292	44,027	23,098	16,604	385	110,551	744
Apr-13	19,698	5,902	43,013	20,301	18,742	343	107,999	720
May-13	19,017	6,362	43,560	21,764	18,823	308	109,835	744
Jun-13	17,444	6,214	48,483	21,509	19,030	308	112,989	720
Jul-13	22,634	7,420	55,161	22,445	18,818	321	126,799	744
Aug-13	21,800	7,280	53,127	22,215	20,295	344	125,061	744
Sep-13	19,057	6,950	48,022	23,078	20,240	366	117,714	720
Oct-13	19,615	6,484	47,500	23,543	19,339	432	116,913	744
Nov-13	21,316	6,443	46,451	24,924	19,706	427	119,267	720
Dec-13	24,935	7,316	48,356	25,484	18,928	455	125,475	744
Jan-14	23,459	6,413	44,506	23,484	18,547	447	116,856	744
Feb-14	22,629	6,540	43,342	24,061	18,723	392	115,687	672
Mar-14	20,452	6,335	44,705	23,602	16,604	388	112,084	744
Apr-14	19,879	5,931	43,582	21,185	18,742	346	109,665	720
May-14	19,222	6,387	44,174	22,186	18,823	311	111,104	744
Jun-14	17,555	6,248	49,124	21,946	19,030	311	114,215	720
Jul-14	22,836	7,454	55,744	22,828	18,818	324	128,004	744
Aug-14	21,998	7,308	53,690	22,629	20,295	347	126,267	744
Sep-14	19,297	6,978	48,619	23,561	20,240	369	119,064	720
Oct-14	19,757	6,523	48,098	23,504	19,339	435	117,657	744
Nov-14	21,506	6,485	47,128	25,440	19,706	430	120,695	720
Dec-14	25,234	7,354	49,042	26,014	18,928	459	127,031	744
Jan-15	23,697	6,440	45,053	23,925	18,547	451	118,113	744
Feb-15	22,886	6,577	43,970	24,565	18,723	395	117,115	672
Mar-15	20,726	6,369	45,398	24,139	16,604	391	113,625	744
Apr-15	20,113	5,961	44,162	21,144	18,742	349	110,472	720
May-15	19,475	6,418	44,791	22,628	18,823	314	112,449	744
Jun-15	17,803	6,281	49,754	22,394	19,030	314	115,577	720
Jul-15	22,998	7,491	56,308	23,216	18,818	327	129,158	744
Aug-15	22,035	7,331	54,217	23,034	20,295	351	127,263	744
Sep-15	19,435	7,009	49,162	24,020	20,240	373	120,239	720
Oct-15	20,005	6,548	48,622	24,377	19,339	438	119,330	744
Nov-15	21,800	6,516	47,715	25,895	19,706	433	122,065	720
Dec-15	25,533	7,387	49,634	26,480	18,928	462	128,423	744
Jan-16	23,945	6,459	45,545	24,316	18,547	454	119,265	744
Feb-16	23,947	6,840	46,143	25,919	18,723	398	121,969	696
Mar-16	21,035	6,401	46,046	24,634	16,604	394	115,114	744
Apr-16	20,350	5,986	44,707	22,016	18,742	353	112,153	720
May-16	19,730	6,444	45,375	23,039	18,823	318	113,729	744
Jun-16	18,053	6,311	50,359	22,818	19,030	318	116,888	720
Jul-16	23,160	7,525	56,860	23,591	18,818	331	130,285	744
Aug-16	22,074	7,352	54,741	23,434	20,295	354	128,250	744
Sep-16	19,585	7,040	49,713	24,482	20,240	376	121,437	720
Oct-16	20,282	6,576	49,176	24,322	19,339	442	120,137	744

Nov-16	22,135	6,550	48,332	26,377	19,706	437	123,537	720
Dec-16	25,882	7,421	50,245	26,961	18,928	466	129,903	744
Jan-17	24,193	6,473	46,018	24,673	18,547	458	120,361	744
Feb-17	23,418	6,628	45,091	25,427	18,723	402	119,689	672
Mar-17	21,289	6,414	46,622	25,050	16,604	398	116,377	744
Apr-17	20,596	6,000	45,175	21,867	18,742	357	112,736	720
May-17	20,000	6,457	45,858	23,351	18,823	322	114,811	744
Jun-17	18,321	6,325	50,840	23,124	19,030	322	117,963	720
Jul-17	23,341	7,541	57,276	23,836	18,818	335	131,148	744
Aug-17	22,128	7,349	55,107	23,685	20,295	358	128,922	744
Sep-17	19,755	7,047	50,076	24,770	20,240	380	122,269	720
Oct-17	20,574	6,580	49,539	25,029	19,339	446	121,508	744
Nov-17	22,486	6,558	48,738	26,651	19,706	441	124,580	720
Dec-17	26,244	7,429	50,647	27,238	18,928	470	130,956	744
Jan-18	24,478	6,467	46,340	24,886	18,547	462	121,179	744
Feb-18	23,717	6,631	45,478	25,688	18,723	406	120,643	672
Mar-18	21,601	6,413	47,053	25,339	16,604	402	117,411	744
Apr-18	20,857	6,002	45,538	22,558	18,742	361	114,057	720
May-18	20,277	6,458	46,247	23,580	18,823	326	115,712	744
Jun-18	18,588	6,330	51,242	23,361	19,030	326	118,878	720
Jul-18	23,505	7,550	57,638	24,031	18,818	339	131,880	744
Aug-18	22,154	7,339	55,431	23,899	20,295	362	129,480	744
Sep-18	19,904	7,049	50,412	25,031	20,240	384	123,020	720
Oct-18	20,860	6,582	49,892	24,784	19,339	450	121,907	744
Nov-18	22,835	6,565	49,142	26,919	19,706	445	125,611	720
Dec-18	26,607	7,436	51,056	27,516	18,928	474	132,018	744
Jan-19	24,776	6,460	46,663	25,098	18,547	466	122,009	744
Feb-19	24,033	6,631	45,861	25,946	18,723	410	121,603	672
Mar-19	21,932	6,409	47,478	25,622	16,604	406	118,450	744
Apr-19	21,135	6,000	45,892	22,317	18,742	365	114,451	720
May-19	20,573	6,457	46,623	23,800	18,823	330	116,605	744
Jun-19	18,871	6,330	51,627	23,585	19,030	330	119,774	720
Jul-19	23,678	7,554	57,978	24,210	18,818	343	132,580	744
Aug-19	22,178	7,324	55,728	24,093	20,295	366	129,985	744
Sep-19	20,059	7,045	50,720	25,271	20,240	388	123,724	720
Oct-19	21,155	6,580	50,227	25,458	19,339	454	123,213	744
Nov-19	23,188	6,566	49,527	27,174	19,706	449	126,611	720
Dec-19	26,966	7,438	51,444	27,779	18,928	478	133,032	744
Jan-20	25,070	6,444	46,969	25,259	18,547	470	122,758	744
Feb-20	25,176	6,857	47,889	27,087	18,723	414	126,145	696
Mar-20	22,281	6,400	47,899	25,854	16,604	410	119,447	744
Apr-20	21,412	5,994	46,253	22,957	18,742	368	115,726	720
May-20	20,867	6,449	47,008	23,984	18,823	333	117,465	744
Jun-20	19,150	6,324	52,022	23,773	19,030	334	120,633	720
Jul-20	23,838	7,548	58,322	24,351	18,818	347	133,224	744
Aug-20	22,189	7,300	56,030	24,247	20,295	370	130,431	744
Sep-20	20,205	7,033	51,034	25,468	20,240	392	124,372	720
Oct-20	21,454	6,571	50,568	25,170	19,339	458	123,560	744
Nov-20	23,551	6,562	49,921	27,387	19,706	453	127,580	720
Dec-20	27,339	7,434	51,843	28,002	18,928	481	134,028	744
Jan-21	25,340	6,430	47,297	25,441	18,547	473	123,527	744
Feb-21	24,630	6,617	46,633	26,381	18,723	418	123,402	672
Mar-21	22,557	6,386	48,332	26,100	16,604	414	120,392	744
Apr-21	21,664	5,985	46,610	22,689	18,742	372	116,062	720
May-21	21,134	6,440	47,382	24,163	18,823	337	118,279	744
Jun-21	19,398	6,314	52,401	23,954	19,030	337	121,434	720
Jul-21	23,963	7,539	58,656	24,489	18,818	350	133,815	744
Aug-21	22,155	7,272	56,317	24,395	20,295	373	130,808	744
Sep-21	20,306	7,017	51,328	25,655	20,240	396	124,942	720
Oct-21	21,708	6,559	50,883	25,780	19,339	461	124,731	744
Nov-21	23,860	6,552	50,283	27,579	19,706	456	128,436	720
Dec-21	27,653	7,424	52,210	28,201	18,928	485	134,902	744
Jan-22	25,615	6,412	47,599	25,598	18,547	477	124,247	744
Feb-22	24,927	6,607	47,008	26,584	18,723	421	124,269	672
Mar-22	22,868	6,371	48,750	26,325	16,604	417	121,335	744
Apr-22	21,923	5,974	46,956	23,306	18,742	376	117,276	720
May-22	21,407	6,428	47,750	24,330	18,823	340	119,079	744
Jun-22	19,650	6,303	52,780	24,125	19,030	341	122,230	720
Jul-22	24,087	7,529	58,998	24,626	18,818	354	134,411	744
Aug-22	22,123	7,245	56,621	24,548	20,295	377	131,209	744
Sep-22	20,421	7,002	51,652	25,857	20,240	399	125,572	720
Oct-22	22,000	6,549	51,243	25,512	19,339	465	125,108	744
Nov-22	24,220	6,547	50,700	27,808	19,706	460	129,440	720
Dec-22	28,023	7,420	52,633	28,441	18,928	488	135,934	744

Jan-23	25,923	6,398	47,939	25,796	18,547	480	125,083	744
Feb-23	25,258	6,601	47,422	26,829	18,723	425	125,259	672
Mar-23	23,212	6,361	49,211	26,592	16,604	421	122,401	744
Apr-23	22,206	5,968	47,347	23,073	18,742	379	117,715	720
May-23	21,701	6,421	48,164	24,541	18,823	344	119,994	744
Jun-23	19,922	6,296	53,199	24,336	19,030	344	123,127	720
Jul-23	24,228	7,522	59,361	24,789	18,818	357	135,075	744
Aug-23	22,099	7,219	56,935	24,719	20,295	380	131,647	744
Sep-23	20,539	6,987	51,975	26,067	20,240	403	126,211	720
Oct-23	22,274	6,538	51,585	26,140	19,339	468	126,345	744
Nov-23	24,550	6,538	51,090	28,024	19,706	463	130,372	720
Dec-23	28,357	7,411	53,025	28,662	18,928	492	136,875	744
Jan-24	26,210	6,385	48,258	25,999	18,547	484	125,882	744
Feb-24	26,438	6,828	49,521	28,046	18,723	428	129,985	696
Mar-24	23,558	6,354	49,645	26,861	16,604	424	123,446	744
Apr-24	22,483	5,961	47,706	23,721	18,742	383	118,995	720
May-24	21,994	6,412	48,542	24,744	18,823	347	120,862	744
Jun-24	20,192	6,288	53,581	24,539	19,030	348	123,979	720
Jul-24	24,359	7,516	59,698	24,951	18,818	361	135,704	744
Aug-24	22,067	7,196	57,228	24,892	20,295	384	132,062	744
Sep-24	20,655	6,975	52,283	26,286	20,240	406	126,846	720
Oct-24	22,561	6,529	51,926	25,893	19,339	472	126,720	744
Nov-24	24,901	6,533	51,486	28,267	19,706	467	131,359	720
Dec-24	28,714	7,407	53,426	28,915	18,928	495	137,886	744
Jan-25	26,464	6,373	48,584	26,213	18,547	487	126,668	744
Feb-25	25,843	6,591	48,211	27,341	18,723	432	127,141	672
Mar-25	23,831	6,342	50,083	27,142	16,604	428	124,429	744
Apr-25	22,734	5,955	48,081	23,508	18,742	386	119,406	720
May-25	22,264	6,405	48,940	24,970	18,823	351	121,753	744
Jun-25	20,445	6,281	53,983	24,766	19,030	351	124,857	720
Jul-25	24,482	7,512	60,046	25,132	18,818	364	136,353	744
Aug-25	22,024	7,174	57,526	25,081	20,295	388	132,488	744
Sep-25	20,773	6,962	52,594	26,519	20,240	410	127,498	720
Oct-25	22,860	6,519	52,266	26,543	19,339	475	128,003	744
Nov-25	25,263	6,526	51,878	28,517	19,706	470	132,360	720
Dec-25	29,077	7,401	53,822	29,173	18,928	499	138,901	744
Jan-26	26,759	6,353	48,907	26,393	18,547	491	127,449	744
Feb-26	26,158	6,580	48,608	27,564	18,723	435	128,068	672
Mar-26	24,156	6,325	50,521	27,381	16,604	431	125,418	744
Apr-26	23,003	5,942	48,442	24,123	18,742	390	120,641	720
May-26	22,546	6,389	49,315	25,141	18,823	355	122,569	744
Jun-26	20,702	6,264	54,355	24,931	19,030	355	125,638	720
Jul-26	24,592	7,495	60,360	25,250	18,818	368	136,883	744
Aug-26	21,962	7,138	57,788	25,204	20,295	391	132,779	744
Sep-26	20,874	6,938	52,868	26,681	20,240	413	128,015	720
Oct-26	23,153	6,501	52,584	26,254	19,339	479	128,311	744
Nov-26	25,625	6,511	52,245	28,705	19,706	474	133,265	720
Dec-26	29,447	7,386	54,191	29,367	18,928	502	139,822	744
Jan-27	27,054	6,326	49,199	26,516	18,547	494	128,136	744
Feb-27	26,478	6,559	48,969	27,726	18,723	439	128,893	672
Mar-27	24,492	6,298	50,921	27,557	16,604	435	126,305	744
Apr-27	23,281	5,921	48,780	23,823	18,742	393	120,939	720
May-27	22,837	6,367	49,671	25,269	18,823	358	123,325	744
Jun-27	20,965	6,241	54,714	25,057	19,030	358	126,367	720
Jul-27	24,709	7,472	60,676	25,339	18,818	371	137,385	744
Aug-27	21,897	7,095	58,054	25,299	20,295	395	133,035	744
Sep-27	20,965	6,907	53,145	26,814	20,240	417	128,488	720
Oct-27	23,416	6,477	52,892	26,804	19,339	482	129,411	744
Nov-27	25,943	6,488	52,602	28,850	19,706	477	134,066	720
Dec-27	29,765	7,363	54,551	29,519	18,928	506	140,633	744
Jan-28	27,328	6,295	49,494	26,635	18,547	498	128,797	744
Feb-28	27,688	6,765	51,101	28,881	18,723	442	133,599	696
Mar-28	24,829	6,271	51,332	27,729	16,604	438	127,203	744
Apr-28	23,557	5,898	49,121	24,378	18,742	397	122,092	720
May-28	23,132	6,342	50,028	25,386	18,823	362	124,072	744
Jun-28	21,237	6,216	55,071	25,171	19,030	362	127,087	720
Jul-28	24,829	7,447	60,987	25,416	18,818	375	137,872	744
Aug-28	21,842	7,051	58,314	25,381	20,295	398	133,281	744
Sep-28	21,077	6,873	53,418	26,933	20,240	420	128,962	720
Oct-28	23,720	6,451	53,202	26,475	19,339	486	129,672	744
Nov-28	26,315	6,463	52,960	28,985	19,706	481	134,910	720
Dec-28	30,143	7,337	54,912	29,660	18,928	510	141,490	744
Jan-29	27,602	6,262	49,785	26,737	18,547	502	129,434	744
Feb-29	27,076	6,508	49,695	28,021	18,723	446	130,468	672

Mar-29	25,125	6,234	51,720	27,874	16,604	442	127,999	744
Apr-29	23,821	5,871	49,450	24,060	18,742	400	122,343	720
May-29	23,410	6,313	50,373	25,487	18,823	365	124,771	744
Jun-29	21,486	6,185	55,416	25,267	19,030	365	127,750	720
Jul-29	24,917	7,417	61,282	25,472	18,818	378	138,285	744
Aug-29	21,743	7,001	58,556	25,441	20,295	402	133,438	744
Sep-29	21,152	6,835	53,676	27,031	20,240	424	129,358	720
Oct-29	23,998	6,421	53,507	26,998	19,339	489	130,753	744
Nov-29	26,658	6,433	53,319	29,111	19,706	484	135,712	720
Dec-29	30,488	7,308	55,275	29,793	18,928	513	142,305	744
Jan-30	27,888	6,226	50,075	26,828	18,547	505	130,069	744
Feb-30	27,389	6,479	50,064	28,152	18,723	449	131,255	672
Mar-30	25,454	6,199	52,137	28,022	16,604	445	128,861	744
Apr-30	24,097	5,845	49,815	24,601	18,742	404	123,503	720
May-30	23,700	6,284	50,760	25,599	18,823	369	125,535	744
Jun-30	21,746	6,155	55,801	25,374	19,030	369	128,475	720
Jul-30	25,012	7,385	61,603	25,532	18,818	382	138,732	744
Aug-30	21,647	6,949	58,821	25,501	20,295	405	133,619	744
Sep-30	21,238	6,794	53,957	27,128	20,240	427	129,784	720
Oct-30	24,293	6,389	53,834	26,664	19,339	493	131,012	744
Nov-30	27,021	6,403	53,700	29,236	19,706	488	136,554	720
Dec-30	30,853	7,278	55,663	29,927	18,928	516	143,166	744
Jan-31	28,177	6,192	50,399	26,948	18,547	508	130,771	744
Feb-31	27,705	6,451	50,464	28,310	18,723	453	132,106	672
Mar-31	25,787	6,165	52,576	28,187	16,604	449	129,768	744
Apr-31	24,378	5,816	50,170	24,295	18,742	407	123,808	720
May-31	23,996	6,253	51,126	25,700	18,823	372	126,269	744
Jun-31	22,008	6,121	56,159	25,466	19,030	372	129,157	720
Jul-31	25,099	7,351	61,912	25,587	18,818	385	139,152	744
Aug-31	21,537	6,895	59,072	25,555	20,295	408	133,762	744
Sep-31	21,312	6,750	54,219	27,216	20,240	431	130,168	720
Oct-31	24,582	6,355	54,134	27,165	19,339	496	132,071	744
Nov-31	27,377	6,368	54,047	29,340	19,706	491	137,329	720
Dec-31	31,207	7,242	56,011	30,035	18,928	520	143,943	744
Jan-32	28,453	6,151	50,679	27,022	18,547	512	131,363	744
Feb-32	28,952	6,641	52,635	29,434	18,723	456	136,841	696
Mar-32	26,116	6,125	52,973	28,307	16,604	452	130,576	744
Apr-32	24,643	5,784	50,507	24,798	18,742	410	124,883	720
May-32	24,274	6,217	51,476	25,776	18,823	375	126,942	744
Jun-32	22,250	6,084	56,505	25,535	19,030	376	129,779	720
Jul-32	25,160	7,313	62,204	25,616	18,818	389	139,500	744
Aug-32	21,394	6,837	59,307	25,584	20,295	412	133,829	744
Sep-32	21,358	6,703	54,469	27,279	20,240	434	130,484	720
Oct-32	24,852	6,317	54,431	26,805	19,339	499	132,244	744
Nov-32	27,710	6,331	54,394	29,428	19,706	494	138,063	720
Dec-32	31,536	7,205	56,361	30,129	18,928	523	144,682	744
Jan-33	28,709	6,109	50,963	27,090	18,547	515	131,933	744
Feb-33	28,288	6,379	51,169	28,517	18,723	459	133,535	672
Mar-33	26,400	6,077	53,348	28,407	16,604	455	131,292	744
Apr-33	24,893	5,746	50,820	24,451	18,742	414	125,065	720
May-33	24,536	6,177	51,801	25,830	18,823	379	127,546	744
Jun-33	22,475	6,040	56,824	25,582	19,030	379	130,330	720
Jul-33	25,199	7,269	62,477	25,629	18,818	392	139,785	744
Aug-33	21,225	6,774	59,522	25,597	20,295	415	133,828	744
Sep-33	21,386	6,650	54,702	27,329	20,240	437	130,744	720
Oct-33	25,112	6,276	54,717	27,273	19,339	503	133,220	744
Nov-33	28,034	6,289	54,732	29,508	19,706	498	138,768	720
Dec-33	31,859	7,163	56,705	30,218	18,928	526	145,399	744
Jan-34	28,966	6,063	51,246	27,157	18,547	518	132,497	744
Feb-34	28,573	6,340	51,533	28,621	18,723	463	134,253	672
Mar-34	26,704	6,032	53,758	28,522	16,604	459	132,078	744
Apr-34	25,148	5,710	51,168	24,945	18,742	417	126,130	720
May-34	24,806	6,137	52,165	25,904	18,823	382	128,217	744
Jun-34	22,706	5,998	57,181	25,647	19,030	382	130,944	720
Jul-34	25,238	7,226	62,778	25,656	18,818	395	140,112	744
Aug-34	21,051	6,711	59,765	25,623	20,295	418	133,863	744
Sep-34	21,415	6,598	54,963	27,392	20,240	440	131,049	720
Oct-34	25,385	6,235	55,031	26,924	19,339	506	133,420	744
Nov-34	28,372	6,248	55,100	29,603	19,706	501	139,530	720
Dec-34	32,192	7,121	57,077	30,320	18,928	530	146,167	744
Jan-35	29,220	6,018	51,548	27,232	18,547	522	133,087	744
Feb-35	28,854	6,301	51,912	28,731	18,723	466	134,987	672
Mar-35	27,001	5,985	54,176	28,638	16,604	462	132,866	744
Apr-35	25,403	5,672	51,520	24,619	18,742	420	126,377	720

May-35	25,074	6,096	52,530	25,974	18,823	385	128,883	744
Jun-35	22,931	5,953	57,537	25,708	19,030	385	131,546	720
Jul-35	25,262	7,181	63,079	25,679	18,818	398	140,418	744
Aug-35	20,856	6,646	60,005	25,643	20,295	422	133,868	744
Sep-35	21,426	6,543	55,222	27,449	20,240	444	131,324	720
Oct-35	25,640	6,191	55,341	27,396	19,339	509	134,416	744
Nov-35	28,692	6,013	54,840	29,693	19,706	504	139,449	720
Dec-35	32,507	6,407	55,755	30,419	18,928	504	144,521	744

	Residential	Commercial no demand	Secondary General	Primary General	Transmission General	Street Lighting	Total Retail
2005	247,002	82,119	505,158	350,861	28,619	3,496	1,217,255
2006	250,787	81,788	517,840	249,088	182,477	3,622	1,285,603
2007	255,314	80,304	529,635	243,176	185,171	3,946	1,297,547
2008	249,798	80,195	532,734	239,285	202,286	4,379	1,308,677
2009	246,596	75,909	536,608	258,163	203,796	4,416	1,325,489
2010	248,126	78,439	541,361	261,539	219,767	4,416	1,353,647
2011	248,182	79,098	549,021	262,683	225,239	4,473	1,368,696
2012	249,473	79,290	556,306	269,794	227,796	4,498	1,387,157
2013	251,498	79,551	564,438	275,068	227,796	4,523	1,402,874
2014	253,823	79,957	571,755	280,440	227,796	4,559	1,418,330
2015	256,506	80,328	578,787	285,816	227,796	4,598	1,433,829
2016	260,179	80,903	587,240	291,908	227,796	4,641	1,452,667
2017	262,344	80,800	590,988	294,701	227,796	4,689	1,461,319
2018	265,381	80,822	595,468	297,592	227,796	4,737	1,471,795
2019	268,543	80,794	599,767	300,353	227,796	4,783	1,482,036
2020	272,531	80,915	605,759	303,539	227,796	4,829	1,495,369
2021	274,367	80,534	608,333	304,828	227,796	4,872	1,500,730
2022	277,263	80,388	612,689	307,059	227,796	4,915	1,510,111
2023	280,270	80,262	617,254	309,568	227,796	4,956	1,520,105
2024	284,132	80,385	623,300	313,114	227,796	4,998	1,533,725
2025	286,062	80,041	626,014	314,904	227,796	5,041	1,539,858
2026	288,975	79,822	630,185	316,994	227,796	5,083	1,548,855
2027	291,802	79,513	634,174	318,574	227,796	5,126	1,556,984
2028	295,696	79,409	639,940	321,029	227,796	5,168	1,569,038
2029	297,476	78,790	642,053	321,292	227,796	5,210	1,572,616
2030	300,337	78,388	646,231	322,563	227,796	5,251	1,580,565
2031	303,163	77,960	650,289	323,803	227,796	5,292	1,588,304
2032	306,699	77,707	655,941	325,713	227,796	5,332	1,599,188
2033	308,116	76,948	657,781	325,433	227,796	5,372	1,601,445
2034	310,555	76,420	661,765	326,314	227,796	5,411	1,608,261
2035	312,868	75,008	663,465	327,182	227,796	5,421	1,611,740

Loss Fctrs	0.0769	0.0769	0.0769	0.0497	0.0256	0.0769		
	Residential Load Fctr	Commercial no demand Load Fctr	Secondary General Load Fctr	Primary General Load Fctr	Transmission General Load Fctr	Street Lighting Load Fctr		Year Month
	0.63	0.83	0.88	0.95	0.94	0.58		Jan-05
	0.61	0.83	0.89	0.96	1.04	0.49		Feb-05
	0.66	0.89	0.92	0.97	1.04	0.56		Mar-05
	0.79	0.82	0.85	0.92	0.90	0.41		Apr-05
	0.68	0.63	0.69	0.84	0.93	0.00		May-05
	0.57	0.64	0.70	0.85	0.93	0.00		Jun-05
	0.67	0.61	0.70	0.86	0.87	0.00		Jul-05
	0.64	0.62	0.70	0.87	1.06	0.00		Aug-05
	0.61	0.65	0.74	0.88	0.93	0.00		Sep-05
	0.75	0.81	0.81	0.90	1.01	0.52		Oct-05
	0.64	0.81	0.86	0.91	0.87	0.55		Nov-05
	0.61	0.80	0.87	0.99	1.08	0.60		Dec-05
	0.63	0.83	0.88	0.95	0.94	0.58		Jan-06
	0.61	0.83	0.89	0.96	1.04	0.48		Feb-06
	0.66	0.89	0.92	0.97	1.04	0.48		Mar-06
	0.79	0.82	0.85	0.92	0.90			Apr-06
	0.68	0.63	0.69	0.84	0.93			May-06
	0.57	0.64	0.70	0.85	0.93			Jun-06
	0.67	0.61	0.70	0.86	0.87			Jul-06
	0.64	0.62	0.70	0.87	1.06			Aug-06
	0.61	0.65	0.74	0.88	0.93			Sep-06
	0.75	0.81	0.81	0.90	1.01	0.52		Oct-06
	0.64	0.81	0.86	0.91	0.87	0.55		Nov-06
	0.61	0.80	0.87	0.99	1.08	0.59		Dec-06
	0.63	0.83	0.88	0.95	0.94	0.58		Jan-07
	0.61	0.83	0.89	0.96	1.04	0.48		Feb-07
	0.66	0.89	0.92	0.97	1.04	0.48		Mar-07
	0.79	0.82	0.85	0.92	0.90			Apr-07
	0.68	0.63	0.69	0.84	0.93			May-07
	0.57	0.64	0.70	0.85	0.93			Jun-07
	0.67	0.61	0.70	0.86	0.87			Jul-07
	0.64	0.62	0.70	0.87	1.06			Aug-07
	0.61	0.65	0.74	0.88	0.93			Sep-07
	0.75	0.81	0.81	0.90	1.01			Oct-07
	0.64	0.81	0.86	0.91	0.87	0.55		Nov-07
	0.61	0.80	0.87	0.99	1.08	0.59		Dec-07
	0.63	0.83	0.88	0.95	0.94	0.58		Jan-08
	0.61	0.83	0.89	0.96	1.04	0.50		Feb-08
	0.66	0.89	0.92	0.97	1.04	0.65		Mar-08
	0.79	0.82	0.85	0.92	0.90	0.41		Apr-08
	0.68	0.63	0.69	0.84	0.93			May-08
	0.57	0.64	0.70	0.85	0.93			Jun-08
	0.67	0.61	0.70	0.86	0.87			Jul-08
	0.64	0.62	0.70	0.87	1.06			Aug-08
	0.61	0.65	0.74	0.88	0.93			Sep-08
	0.75	0.81	0.81	0.90	1.01	0.52		Oct-08
	0.64	0.81	0.86	0.91	0.87	0.55		Nov-08
	0.61	0.80	0.87	0.99	1.08	0.59		Dec-08
	0.63	0.83	0.88	0.95	0.94	0.574966024		Jan-09
	0.61	0.83	0.89	0.96	1.04	0.481642772		Feb-09
	0.66	0.89	0.92	0.97	1.04	0.48067839		Mar-09
	0.79	0.82	0.85	0.92	0.90	0.411951165		Apr-09
	0.68	0.63	0.69	0.84	0.93			May-09
	0.57	0.64	0.70	0.85	0.93			Jun-09
	0.67	0.61	0.70	0.86	0.87			Jul-09
	0.64	0.62	0.70	0.87	1.06			Aug-09
	0.61	0.65	0.74	0.88	0.93			Sep-09
	0.75	0.81	0.81	0.90	1.01	0.516722297		Oct-09
	0.64	0.81	0.86	0.91	0.87	0.546180556		Nov-09
	0.61	0.80	0.87	0.99	1.08	0.588832512		Dec-09
	0.63	0.83	0.88	0.95	0.94	0.575190039		Jan-10
	0.61	0.83	0.89	0.96	1.04	0.482045998		Feb-10
	0.66	0.89	0.92	0.97	1.04	0.704220142		Mar-10
	0.79	0.82	0.85	0.92	0.90	0.412399194		Apr-10
	0.68	0.63	0.69	0.84	0.93			May-10
	0.57	0.64	0.70	0.85	0.93			Jun-10
	0.67	0.61	0.70	0.86	0.87			Jul-10
	0.64	0.62	0.70	0.87	1.06			Aug-10

0.61	0.65	0.74	0.88	0.93		Sep-10
0.75	0.81	0.81	0.90	1.01		Oct-10
0.64	0.81	0.86	0.91	0.87	0.545889337	Nov-10
0.61	0.80	0.87	0.99	1.08	0.630842503	Dec-10
0.63	0.83	0.88	0.95	0.94	0.575279645	Jan-11
0.61	0.83	0.89	0.96	1.04	0.485522625	Feb-11
0.66	0.89	0.92	0.97	1.04	0.560527482	Mar-11
0.79	0.82	0.85	0.92	0.90	0.412025836	Apr-11
0.68	0.63	0.69	0.84	0.93		May-11
0.57	0.64	0.70	0.85	0.93		Jun-11
0.67	0.61	0.70	0.86	0.87		Jul-11
0.64	0.62	0.70	0.87	1.06		Aug-11
0.61	0.65	0.74	0.88	0.93		Sep-11
0.75	0.81	0.81	0.90	1.01	0.516640158	Oct-11
0.64	0.81	0.86	0.91	0.87	0.545978943	Nov-11
0.61	0.80	0.87	0.99	1.08	0.597194187	Dec-11
0.63	0.83	0.88	0.95	0.94	0.58	Jan-12
0.61	0.83	0.89	0.96	1.04	0.49	Feb-12
0.66	0.89	0.92	0.97	1.04	0.56	Mar-12
0.79	0.82	0.85	0.92	0.90	0.41	Apr-12
0.68	0.63	0.69	0.84	0.93	0.00	May-12
0.57	0.64	0.70	0.85	0.93	0.00	Jun-12
0.67	0.61	0.70	0.86	0.87	0.00	Jul-12
0.64	0.62	0.70	0.87	1.06	0.00	Aug-12
0.61	0.65	0.74	0.88	0.93	0.00	Sep-12
0.75	0.81	0.81	0.90	1.01	0.52	Oct-12
0.64	0.81	0.86	0.91	0.87	0.55	Nov-12
0.61	0.80	0.87	0.99	1.08	0.60	Dec-12
0.63	0.83	0.88	0.95	0.94	0.58	Jan-13
0.61	0.83	0.89	0.96	1.04	0.49	Feb-13
0.66	0.89	0.92	0.97	1.04	0.56	Mar-13
0.79	0.82	0.85	0.92	0.90	0.41	Apr-13
0.68	0.63	0.69	0.84	0.93	0.00	May-13
0.57	0.64	0.70	0.85	0.93	0.00	Jun-13
0.67	0.61	0.70	0.86	0.87	0.00	Jul-13
0.64	0.62	0.70	0.87	1.06	0.00	Aug-13
0.61	0.65	0.74	0.88	0.93	0.00	Sep-13
0.75	0.81	0.81	0.90	1.01	0.52	Oct-13
0.64	0.81	0.86	0.91	0.87	0.55	Nov-13
0.61	0.80	0.87	0.99	1.08	0.60	Dec-13
0.63	0.83	0.88	0.95	0.94	0.58	Jan-14
0.61	0.83	0.89	0.96	1.04	0.49	Feb-14
0.66	0.89	0.92	0.97	1.04	0.56	Mar-14
0.79	0.82	0.85	0.92	0.90	0.41	Apr-14
0.68	0.63	0.69	0.84	0.93	0.00	May-14
0.57	0.64	0.70	0.85	0.93	0.00	Jun-14
0.67	0.61	0.70	0.86	0.87	0.00	Jul-14
0.64	0.62	0.70	0.87	1.06	0.00	Aug-14
0.61	0.65	0.74	0.88	0.93	0.00	Sep-14
0.75	0.81	0.81	0.90	1.01	0.52	Oct-14
0.64	0.81	0.86	0.91	0.87	0.55	Nov-14
0.61	0.80	0.87	0.99	1.08	0.60	Dec-14
0.63	0.83	0.88	0.95	0.94	0.58	Jan-15
0.61	0.83	0.89	0.96	1.04	0.49	Feb-15
0.66	0.89	0.92	0.97	1.04	0.56	Mar-15
0.79	0.82	0.85	0.92	0.90	0.41	Apr-15
0.68	0.63	0.69	0.84	0.93	0.00	May-15
0.57	0.64	0.70	0.85	0.93	0.00	Jun-15
0.67	0.61	0.70	0.86	0.87	0.00	Jul-15
0.64	0.62	0.70	0.87	1.06	0.00	Aug-15
0.61	0.65	0.74	0.88	0.93	0.00	Sep-15
0.75	0.81	0.81	0.90	1.01	0.52	Oct-15
0.64	0.81	0.86	0.91	0.87	0.55	Nov-15
0.61	0.80	0.87	0.99	1.08	0.60	Dec-15
0.63	0.83	0.88	0.95	0.94	0.58	Jan-16
0.61	0.83	0.89	0.96	1.04	0.49	Feb-16
0.66	0.89	0.92	0.97	1.04	0.56	Mar-16
0.79	0.82	0.85	0.92	0.90	0.41	Apr-16
0.68	0.63	0.69	0.84	0.93	0.00	May-16
0.57	0.64	0.70	0.85	0.93	0.00	Jun-16
0.67	0.61	0.70	0.86	0.87	0.00	Jul-16
0.64	0.62	0.70	0.87	1.06	0.00	Aug-16
0.61	0.65	0.74	0.88	0.93	0.00	Sep-16
0.75	0.81	0.81	0.90	1.01	0.52	Oct-16

0.64	0.81	0.86	0.91	0.87	0.55	Nov-16
0.61	0.80	0.87	0.99	1.08	0.60	Dec-16
0.63	0.83	0.88	0.95	0.94	0.58	Jan-17
0.61	0.83	0.89	0.96	1.04	0.49	Feb-17
0.66	0.89	0.92	0.97	1.04	0.56	Mar-17
0.79	0.82	0.85	0.92	0.90	0.41	Apr-17
0.68	0.63	0.69	0.84	0.93	0.00	May-17
0.57	0.64	0.70	0.85	0.93	0.00	Jun-17
0.67	0.61	0.70	0.86	0.87	0.00	Jul-17
0.64	0.62	0.70	0.87	1.06	0.00	Aug-17
0.61	0.65	0.74	0.88	0.93	0.00	Sep-17
0.75	0.81	0.81	0.90	1.01	0.52	Oct-17
0.64	0.81	0.86	0.91	0.87	0.55	Nov-17
0.61	0.80	0.87	0.99	1.08	0.60	Dec-17
0.63	0.83	0.88	0.95	0.94	0.58	Jan-18
0.61	0.83	0.89	0.96	1.04	0.49	Feb-18
0.66	0.89	0.92	0.97	1.04	0.56	Mar-18
0.79	0.82	0.85	0.92	0.90	0.41	Apr-18
0.68	0.63	0.69	0.84	0.93	0.00	May-18
0.57	0.64	0.70	0.85	0.93	0.00	Jun-18
0.67	0.61	0.70	0.86	0.87	0.00	Jul-18
0.64	0.62	0.70	0.87	1.06	0.00	Aug-18
0.61	0.65	0.74	0.88	0.93	0.00	Sep-18
0.75	0.81	0.81	0.90	1.01	0.52	Oct-18
0.64	0.81	0.86	0.91	0.87	0.55	Nov-18
0.61	0.80	0.87	0.99	1.08	0.60	Dec-18
0.63	0.83	0.88	0.95	0.94	0.58	Jan-19
0.61	0.83	0.89	0.96	1.04	0.49	Feb-19
0.66	0.89	0.92	0.97	1.04	0.56	Mar-19
0.79	0.82	0.85	0.92	0.90	0.41	Apr-19
0.68	0.63	0.69	0.84	0.93	0.00	May-19
0.57	0.64	0.70	0.85	0.93	0.00	Jun-19
0.67	0.61	0.70	0.86	0.87	0.00	Jul-19
0.64	0.62	0.70	0.87	1.06	0.00	Aug-19
0.61	0.65	0.74	0.88	0.93	0.00	Sep-19
0.75	0.81	0.81	0.90	1.01	0.52	Oct-19
0.64	0.81	0.86	0.91	0.87	0.55	Nov-19
0.61	0.80	0.87	0.99	1.08	0.60	Dec-19
0.63	0.83	0.88	0.95	0.94	0.58	Jan-20
0.61	0.83	0.89	0.96	1.04	0.49	Feb-20
0.66	0.89	0.92	0.97	1.04	0.56	Mar-20
0.79	0.82	0.85	0.92	0.90	0.41	Apr-20
0.68	0.63	0.69	0.84	0.93	0.00	May-20
0.57	0.64	0.70	0.85	0.93	0.00	Jun-20
0.67	0.61	0.70	0.86	0.87	0.00	Jul-20
0.64	0.62	0.70	0.87	1.06	0.00	Aug-20
0.61	0.65	0.74	0.88	0.93	0.00	Sep-20
0.75	0.81	0.81	0.90	1.01	0.52	Oct-20
0.64	0.81	0.86	0.91	0.87	0.55	Nov-20
0.61	0.80	0.87	0.99	1.08	0.60	Dec-20
0.63	0.83	0.88	0.95	0.94	0.58	Jan-21
0.61	0.83	0.89	0.96	1.04	0.49	Feb-21
0.66	0.89	0.92	0.97	1.04	0.56	Mar-21
0.79	0.82	0.85	0.92	0.90	0.41	Apr-21
0.68	0.63	0.69	0.84	0.93	0.00	May-21
0.57	0.64	0.70	0.85	0.93	0.00	Jun-21
0.67	0.61	0.70	0.86	0.87	0.00	Jul-21
0.64	0.62	0.70	0.87	1.06	0.00	Aug-21
0.61	0.65	0.74	0.88	0.93	0.00	Sep-21
0.75	0.81	0.81	0.90	1.01	0.52	Oct-21
0.64	0.81	0.86	0.91	0.87	0.55	Nov-21
0.61	0.80	0.87	0.99	1.08	0.60	Dec-21
0.63	0.83	0.88	0.95	0.94	0.58	Jan-22
0.61	0.83	0.89	0.96	1.04	0.49	Feb-22
0.66	0.89	0.92	0.97	1.04	0.56	Mar-22
0.79	0.82	0.85	0.92	0.90	0.41	Apr-22
0.68	0.63	0.69	0.84	0.93	0.00	May-22
0.57	0.64	0.70	0.85	0.93	0.00	Jun-22
0.67	0.61	0.70	0.86	0.87	0.00	Jul-22
0.64	0.62	0.70	0.87	1.06	0.00	Aug-22
0.61	0.65	0.74	0.88	0.93	0.00	Sep-22
0.75	0.81	0.81	0.90	1.01	0.52	Oct-22
0.64	0.81	0.86	0.91	0.87	0.55	Nov-22
0.61	0.80	0.87	0.99	1.08	0.60	Dec-22

0.63	0.83	0.88	0.95	0.94	0.58	Jan-23
0.61	0.83	0.89	0.96	1.04	0.49	Feb-23
0.66	0.89	0.92	0.97	1.04	0.56	Mar-23
0.79	0.82	0.85	0.92	0.90	0.41	Apr-23
0.68	0.63	0.69	0.84	0.93	0.00	May-23
0.57	0.64	0.70	0.85	0.93	0.00	Jun-23
0.67	0.61	0.70	0.86	0.87	0.00	Jul-23
0.64	0.62	0.70	0.87	1.06	0.00	Aug-23
0.61	0.65	0.74	0.88	0.93	0.00	Sep-23
0.75	0.81	0.81	0.90	1.01	0.52	Oct-23
0.64	0.81	0.86	0.91	0.87	0.55	Nov-23
0.61	0.80	0.87	0.99	1.08	0.60	Dec-23
0.63	0.83	0.88	0.95	0.94	0.58	Jan-24
0.61	0.83	0.89	0.96	1.04	0.49	Feb-24
0.66	0.89	0.92	0.97	1.04	0.56	Mar-24
0.79	0.82	0.85	0.92	0.90	0.41	Apr-24
0.68	0.63	0.69	0.84	0.93	0.00	May-24
0.57	0.64	0.70	0.85	0.93	0.00	Jun-24
0.67	0.61	0.70	0.86	0.87	0.00	Jul-24
0.64	0.62	0.70	0.87	1.06	0.00	Aug-24
0.61	0.65	0.74	0.88	0.93	0.00	Sep-24
0.75	0.81	0.81	0.90	1.01	0.52	Oct-24
0.64	0.81	0.86	0.91	0.87	0.55	Nov-24
0.61	0.80	0.87	0.99	1.08	0.60	Dec-24
0.63	0.83	0.88	0.95	0.94	0.58	Jan-25
0.61	0.83	0.89	0.96	1.04	0.49	Feb-25
0.66	0.89	0.92	0.97	1.04	0.56	Mar-25
0.79	0.82	0.85	0.92	0.90	0.41	Apr-25
0.68	0.63	0.69	0.84	0.93	0.00	May-25
0.57	0.64	0.70	0.85	0.93	0.00	Jun-25
0.67	0.61	0.70	0.86	0.87	0.00	Jul-25
0.64	0.62	0.70	0.87	1.06	0.00	Aug-25
0.61	0.65	0.74	0.88	0.93	0.00	Sep-25
0.75	0.81	0.81	0.90	1.01	0.52	Oct-25
0.64	0.81	0.86	0.91	0.87	0.55	Nov-25
0.61	0.80	0.87	0.99	1.08	0.60	Dec-25
0.63	0.83	0.88	0.95	0.94	0.58	Jan-26
0.61	0.83	0.89	0.96	1.04	0.49	Feb-26
0.66	0.89	0.92	0.97	1.04	0.56	Mar-26
0.79	0.82	0.85	0.92	0.90	0.41	Apr-26
0.68	0.63	0.69	0.84	0.93	0.00	May-26
0.57	0.64	0.70	0.85	0.93	0.00	Jun-26
0.67	0.61	0.70	0.86	0.87	0.00	Jul-26
0.64	0.62	0.70	0.87	1.06	0.00	Aug-26
0.61	0.65	0.74	0.88	0.93	0.00	Sep-26
0.75	0.81	0.81	0.90	1.01	0.52	Oct-26
0.64	0.81	0.86	0.91	0.87	0.55	Nov-26
0.61	0.80	0.87	0.99	1.08	0.60	Dec-26
0.63	0.83	0.88	0.95	0.94	0.58	Jan-27
0.61	0.83	0.89	0.96	1.04	0.49	Feb-27
0.66	0.89	0.92	0.97	1.04	0.56	Mar-27
0.79	0.82	0.85	0.92	0.90	0.41	Apr-27
0.68	0.63	0.69	0.84	0.93	0.00	May-27
0.57	0.64	0.70	0.85	0.93	0.00	Jun-27
0.67	0.61	0.70	0.86	0.87	0.00	Jul-27
0.64	0.62	0.70	0.87	1.06	0.00	Aug-27
0.61	0.65	0.74	0.88	0.93	0.00	Sep-27
0.75	0.81	0.81	0.90	1.01	0.52	Oct-27
0.64	0.81	0.86	0.91	0.87	0.55	Nov-27
0.61	0.80	0.87	0.99	1.08	0.60	Dec-27
0.63	0.83	0.88	0.95	0.94	0.58	Jan-28
0.61	0.83	0.89	0.96	1.04	0.49	Feb-28
0.66	0.89	0.92	0.97	1.04	0.56	Mar-28
0.79	0.82	0.85	0.92	0.90	0.41	Apr-28
0.68	0.63	0.69	0.84	0.93	0.00	May-28
0.57	0.64	0.70	0.85	0.93	0.00	Jun-28
0.67	0.61	0.70	0.86	0.87	0.00	Jul-28
0.64	0.62	0.70	0.87	1.06	0.00	Aug-28
0.61	0.65	0.74	0.88	0.93	0.00	Sep-28
0.75	0.81	0.81	0.90	1.01	0.52	Oct-28
0.64	0.81	0.86	0.91	0.87	0.55	Nov-28
0.61	0.80	0.87	0.99	1.08	0.60	Dec-28
0.63	0.83	0.88	0.95	0.94	0.58	Jan-29
0.61	0.83	0.89	0.96	1.04	0.49	Feb-29

0.66	0.89	0.92	0.97	1.04	0.56	Mar-29
0.79	0.82	0.85	0.92	0.90	0.41	Apr-29
0.68	0.63	0.69	0.84	0.93	0.00	May-29
0.57	0.64	0.70	0.85	0.93	0.00	Jun-29
0.67	0.61	0.70	0.86	0.87	0.00	Jul-29
0.64	0.62	0.70	0.87	1.06	0.00	Aug-29
0.61	0.65	0.74	0.88	0.93	0.00	Sep-29
0.75	0.81	0.81	0.90	1.01	0.52	Oct-29
0.64	0.81	0.86	0.91	0.87	0.55	Nov-29
0.61	0.80	0.87	0.99	1.08	0.60	Dec-29
0.63	0.83	0.88	0.95	0.94	0.58	Jan-30
0.61	0.83	0.89	0.96	1.04	0.49	Feb-30
0.66	0.89	0.92	0.97	1.04	0.56	Mar-30
0.79	0.82	0.85	0.92	0.90	0.41	Apr-30
0.68	0.63	0.69	0.84	0.93	0.00	May-30
0.57	0.64	0.70	0.85	0.93	0.00	Jun-30
0.67	0.61	0.70	0.86	0.87	0.00	Jul-30
0.64	0.62	0.70	0.87	1.06	0.00	Aug-30
0.61	0.65	0.74	0.88	0.93	0.00	Sep-30
0.75	0.81	0.81	0.90	1.01	0.52	Oct-30
0.64	0.81	0.86	0.91	0.87	0.55	Nov-30
0.61	0.80	0.87	0.99	1.08	0.60	Dec-30
0.63	0.83	0.88	0.95	0.94	0.58	Jan-31
0.61	0.83	0.89	0.96	1.04	0.49	Feb-31
0.66	0.89	0.92	0.97	1.04	0.56	Mar-31
0.79	0.82	0.85	0.92	0.90	0.41	Apr-31
0.68	0.63	0.69	0.84	0.93	0.00	May-31
0.57	0.64	0.70	0.85	0.93	0.00	Jun-31
0.67	0.61	0.70	0.86	0.87	0.00	Jul-31
0.64	0.62	0.70	0.87	1.06	0.00	Aug-31
0.61	0.65	0.74	0.88	0.93	0.00	Sep-31
0.75	0.81	0.81	0.90	1.01	0.52	Oct-31
0.64	0.81	0.86	0.91	0.87	0.55	Nov-31
0.61	0.80	0.87	0.99	1.08	0.60	Dec-31
0.63	0.83	0.88	0.95	0.94	0.58	Jan-32
0.61	0.83	0.89	0.96	1.04	0.49	Feb-32
0.66	0.89	0.92	0.97	1.04	0.56	Mar-32
0.79	0.82	0.85	0.92	0.90	0.41	Apr-32
0.68	0.63	0.69	0.84	0.93	0.00	May-32
0.57	0.64	0.70	0.85	0.93	0.00	Jun-32
0.67	0.61	0.70	0.86	0.87	0.00	Jul-32
0.64	0.62	0.70	0.87	1.06	0.00	Aug-32
0.61	0.65	0.74	0.88	0.93	0.00	Sep-32
0.75	0.81	0.81	0.90	1.01	0.52	Oct-32
0.64	0.81	0.86	0.91	0.87	0.55	Nov-32
0.61	0.80	0.87	0.99	1.08	0.60	Dec-32
0.63	0.83	0.88	0.95	0.94	0.58	Jan-33
0.61	0.83	0.89	0.96	1.04	0.49	Feb-33
0.66	0.89	0.92	0.97	1.04	0.56	Mar-33
0.79	0.82	0.85	0.92	0.90	0.41	Apr-33
0.68	0.63	0.69	0.84	0.93	0.00	May-33
0.57	0.64	0.70	0.85	0.93	0.00	Jun-33
0.67	0.61	0.70	0.86	0.87	0.00	Jul-33
0.64	0.62	0.70	0.87	1.06	0.00	Aug-33
0.61	0.65	0.74	0.88	0.93	0.00	Sep-33
0.75	0.81	0.81	0.90	1.01	0.52	Oct-33
0.64	0.81	0.86	0.91	0.87	0.55	Nov-33
0.61	0.80	0.87	0.99	1.08	0.60	Dec-33
0.63	0.83	0.88	0.95	0.94	0.58	Jan-34
0.61	0.83	0.89	0.96	1.04	0.49	Feb-34
0.66	0.89	0.92	0.97	1.04	0.56	Mar-34
0.79	0.82	0.85	0.92	0.90	0.41	Apr-34
0.68	0.63	0.69	0.84	0.93	0.00	May-34
0.57	0.64	0.70	0.85	0.93	0.00	Jun-34
0.67	0.61	0.70	0.86	0.87	0.00	Jul-34
0.64	0.62	0.70	0.87	1.06	0.00	Aug-34
0.61	0.65	0.74	0.88	0.93	0.00	Sep-34
0.75	0.81	0.81	0.90	1.01	0.52	Oct-34
0.64	0.81	0.86	0.91	0.87	0.55	Nov-34
0.61	0.80	0.87	0.99	1.08	0.60	Dec-34
0.63	0.83	0.88	0.95	0.94	0.58	Jan-35
0.61	0.83	0.89	0.96	1.04	0.49	Feb-35
0.66	0.89	0.92	0.97	1.04	0.56	Mar-35
0.79	0.82	0.85	0.92	0.90	0.41	Apr-35

0.68	0.63	0.69	0.84	0.93	0.00	May-35
0.57	0.64	0.70	0.85	0.93	0.00	Jun-35
0.67	0.61	0.70	0.86	0.87	0.00	Jul-35
0.64	0.62	0.70	0.87	1.06	0.00	Aug-35
0.61	0.65	0.74	0.88	0.93	0.00	Sep-35
0.75	0.81	0.81	0.90	1.01	0.52	Oct-35
0.64	0.81	0.86	0.91	0.87	0.55	Nov-35
0.61	0.80	0.87	0.99	1.08	0.60	Dec-35

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Residential MW	Commercial no demand MW	Secondary General MW	Primary General MW	Transmission General MW	Street Lighting MW	Total Retail MW
57	12	69	47	0	1	187
56	12	65	45	0	1	180
43	10	63	45	0	1	163
35	11	68	45	0	1	160
41	15	84	46	0	0	186
45	15	93	48	0	0	201
48	15	83	44	0	0	190
49	14	73	65	0	0	202
43	28	101	47	0	0	220
39	7	89	58	0	1	194
48	13	79	46	23	1	210
59	13	73	21	18	1	185
55	13	66	19	21	1	175
54	10	67	15	20	1	166
43	11	63	21	20	1	159
38	13	70	36	23	0	180
36	15	87	78	23	0	240
47	15	90	31	24	0	206
53	19	106	33	25	0	237
47	17	93	27	21	0	205
48	16	95	33	23	0	216
35	11	77	20	21	1	166
49	12	75	48	24	1	209
65	13	80	37	19	1	215
55	11	64	30	23	1	184
58	12	72	32	20	1	196
47	10	65	32	21	1	177
36	12	72	33	24	0	177
39	14	87	37	23	0	200
47	15	98	29	24	0	213
50	18	104	22	25	0	218
49	17	98	23	21	0	208
56	17	99	41	23	0	237
34	12	80	36	22	0	184
48	12	76	35	26	1	198
63	13	76	33	19	1	207
55	11	66	30	24	1	186
56	12	69	16	22	1	176
49	11	70	19	22	1	172
35	11	70	30	27	1	173
39	14	90	38	25	0	207
47	15	96	38	26	0	222
45	17	104	36	28	0	231
52	17	95	38	23	0	225
48	17	103	41	26	0	235
34	12	79	26	24	1	176
49	12	75	40	28	1	205
59	13	76	30	21	1	200
57	12	68	30	25	1	194
55	12	74	34	22	1	198
43	10	65	30	22	1	171
35	10	72	33	26	1	179
42	15	97	38	25	0	217
43	14	96	22	25	0	200
44	16	102	45	28	0	235
47	16	108	37	23	0	232
45	15	92	38	27	0	217
36	11	80	35	24	1	187
55	12	75	36	28	1	207
57	12	75	30	23	1	199
60	12	72	29	26	1	200
55	11	74	38	23	1	202
45	10	64	29	24	1	173
34	10	71	32	29	1	178
41	14	92	38	28	0	213
45	14	98	34	29	0	219
48	17	108	36	31	0	240
50	17	106	38	26	0	236

46	16	91	37	28	0	217
37	13	86	38	26	0	199
46	12	77	37	29	1	202
59	13	75	31	22	1	201
53	11	70	30	27	1	192
58	13	76	34	27	1	210
44	10	67	29	22	1	172
37	11	73	35	29	1	186
40	15	93	35	28	0	210
46	14	100	34	29	0	222
48	17	110	37	29	0	242
49	17	107	37	26	0	236
46	16	94	38	31	0	224
37	11	82	37	26	1	194
49	12	79	39	32	1	211
58	13	78	33	24	1	207
53	11	71	34	27	1	198
57	12	74	34	27	1	205
44	10	68	31	22	1	177
37	11	75	36	30	1	189
40	15	90	35	28	0	208
46	15	102	36	29	0	227
49	17	112	37	30	0	245
49	17	109	35	26	0	237
46	16	95	39	31	0	227
38	12	83	35	26	1	195
49	12	80	39	32	1	213
58	13	79	36	24	1	211
54	11	72	34	27	1	200
59	12	77	38	28	1	216
44	10	70	34	22	1	181
37	11	76	32	30	1	187
40	15	92	36	28	0	211
46	15	103	37	29	0	229
49	18	114	37	30	0	247
49	17	110	36	26	0	239
47	16	97	38	31	0	229
38	12	85	37	26	1	198
49	12	81	40	32	1	215
59	13	80	36	24	1	214
54	11	73	35	27	1	202
59	13	78	39	28	1	218
45	10	71	34	22	1	184
38	11	77	33	30	1	190
41	15	93	37	28	0	213
46	15	104	37	29	0	232
50	18	115	37	30	0	249
50	17	112	37	26	0	242
47	16	98	39	31	0	232
38	12	86	37	26	1	200
50	12	82	41	32	1	218
59	13	81	37	24	1	216
55	11	74	36	27	1	204
60	13	80	40	28	1	221
46	10	72	35	22	1	186
38	11	78	33	30	1	191
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48	16	99	40	31	0	234
39	12	87	38	26	1	203
51	12	83	41	32	1	221
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55	11	75	36	27	1	206
60	13	81	41	27	1	222
46	10	73	36	22	1	189
38	11	79	35	30	1	194
42	15	95	39	28	0	219
48	15	107	39	29	0	237
50	18	117	39	30	0	254
50	17	114	38	26	0	246
48	16	100	41	31	0	237
39	12	88	38	26	1	204

51	12	84	42	32	1	223
61	13	83	39	24	1	221
56	11	76	37	27	1	208
61	13	82	41	28	1	226
47	10	74	37	22	1	191
39	11	80	35	30	1	195
42	15	96	39	28	0	221
48	15	108	39	29	0	240
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62	13	84	39	24	1	223
57	11	76	37	27	1	209
62	13	82	42	28	1	228
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49	15	109	40	29	0	242
51	18	119	39	30	0	257
50	17	115	39	26	0	248
49	16	102	42	31	0	240
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53	12	86	43	32	1	227
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57	11	77	37	27	1	211
63	13	83	42	28	1	229
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40	11	81	35	30	1	198
44	15	98	40	28	0	224
50	15	110	40	29	0	244
51	18	119	40	30	0	258
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58	11	77	38	27	1	212
63	13	84	42	27	1	230
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40	11	81	36	30	1	200
44	15	99	40	28	0	226
51	15	110	41	29	0	246
52	18	120	40	30	0	259
50	17	116	39	26	0	250
50	16	103	42	31	0	242
42	12	90	39	26	1	210
55	12	87	44	32	1	231
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59	11	78	38	27	1	214
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62	11	81	39	27	1	222
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56	15	117	43	29	0	260
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74	12	93	46	28	2	254
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67	11	84	40	27	1	231
75	12	93	46	28	2	256
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60	14	121	44	29	0	268
55	17	129	42	30	0	273
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67	10	85	40	27	1	232
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48	10	91	39	30	2	219

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53	18	124	41	30	0	266
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54	18	125	42	30	0	268
54	18	126	42	30	0	269
54	18	126	42	30	0	269
54	18	127	42	30	0	270
55	17	128	42	30	0	271
55	17	128	42	30	0	272
55	17	129	42	30	0	272
55	17	129	42	30	0	273
55	17	130	42	30	0	274

AMENDED AND RESTATED

POWER PURCHASE AGREEMENT

between

PUBLIC SERVICE COMPANY OF COLORADO

and

YAMPA VALLEY ELECTRIC ASSOCIATION, INC.

Dated: February 3, 1992, as amended as of January 1, 2004, May 1, 2008, July 2, 2010 and April 11, 2012

ARTICLE I DEFINITIONS 1

1.1 "Agreement" 1
1.2 "Assured Power and Energy Requirements" 1
1.3 "Authorized Operating Representatives" 1
1.4 "Customer Eligible Renewable Purchased Power" 2
1.5 "FERC" 2
1.6 "Full Requirements Service" 2
1.7 "Law" 2
1.8 "Moody's" 2
1.9 "Partial Requirements Service" 2
1.10 "Performance Assurance" 2
1.11 "Points of Delivery" 2
1.12 "Total Power and Energy Requirements" 2
1.13 "S&P" 2
1.14 "Western" 2
1.15 "Western Preference Power" 3

ARTICLE II TERM AND REGULATORY APPROVAL 3

2.1 Effective Date. 3
2.2 Initial Term. 3
2.3 General Obligations. 3
2.4 FERC 3
2.5 RUS Approval 3

ARTICLE III CONDITIONS OF SERVICE 3

3.1 Purchases 3
3.2 Early Termination Options. 4
3.3 Reserves. 4
3.4 Specifications of Power and Energy. 4

ARTICLE IV WESTERN PREFERENCE POWER AND CUSTOMER ELIGIBLE RENEWABLE PURCHASED POWER 4

4.1 Monthly Schedules of Western Preference Power 4
4.2 Changes in Western Preference Power. 4
4.3 Transmission of Western Preference Power. 4
4.4 Scheduling and Accounting of Customer Eligible Renewable Purchased Power. 4

ARTICLE V RATE 5

5.1 Rate. 5
5.2 Change in Rate. 5

ARTICLE VI BILLING 5

6.1 Monthly Invoices. 5
6.2 Disputed Payment. 5

ARTICLE VII FORECASTS AND SCHEDULES 6

7.1 Annual Forecast. 6

7.2 Monthly Western Schedules. 6
7.3 Other Information. 6

ARTICLE VIII FACILITIES 6

8.1 Service Continuity. 6
8.2 Delivery Facilities. 6
8.3 Facilities Provided by Public Service. 7
8.4 Facilities Provided by Customer. 7

ARTICLE IX POWER FACTOR 7

ARTICLE X RELATIONSHIP OF THE PARTIES 7

ARTICLE XI AUTHORIZED OPERATING REPRESENTATIVES 7

ARTICLE XII NOTICES 8

ARTICLE XIII CHANGES IN CHARGES AND TERMS AND CONDITIONS OF SERVICE 9

ARTICLE XIV ENVIRONMENTAL COSTS AND EMISSIONS ALLOWANCES 9

ARTICLE XV CREDITWORTHINESS 10

ARTICLE XVI EVENTS OF DEFAULT; REMEDIES 11

ARTICLE XVII UNCONTROLLABLE FORCE AND INDEMNIFICATION 13

17.1 Uncontrollable Force. 13
17.2 Indemnification. 13

ARTICLE XVIII LIMITATION OF LIABILITY 13

ARTICLE XIX WAIVER 13

ARTICLE XX ARBITRATION 14

ARTICLE XXI ENTIRE AGREEMENT 14

ARTICLE XXII COUNTERPARTS 14

ARTICLE XXIII ASSIGNMENT 14

ARTICLE XXIV AMENDMENT; SEVERABILITY 15

ARTICLE XXV GOVERNING LAW 15

EXHIBIT A WESTERN PREFERENCE POWER 17

EXHIBIT B POINTS OF DELIVERY OF YAMPA VALLEY ELECTRIC ASSOCIATION 18

EXHIBIT C EARLY TERMINATION OPTION 19

RATE SCHEDULE A 20

Appendix A [RESERVED] 28

Appendix B-1 RENEWABLE ENERGY CERTIFICATE RIDER (AMENDED) 29

Appendix B-2 AMENDED AND RESTATED RENEWABLE ENERGY CREDIT OWNERSHIP AGREEMENT 33

ATTACHMENT 1 TO APPENDIX B-2: DESIGNATED ELIGIBLE ENERGY RESOURCES: 40

AMENDED AND RESTATED

POWER PURCHASE AGREEMENT

THIS AMENDED AND RESTATED POWER PURCHASE AGREEMENT (hereinafter "Agreement" or "PPA") by and between PUBLIC SERVICE COMPANY OF COLORADO, 1800 Larimer Street, Denver, Colorado 80202, a Colorado corporation, hereinafter referred to as "Company," "Public Service," or "PSCo", and the YAMPA VALLEY ELECTRIC ASSOCIATION, a Colorado cooperative electric association, P.O. Box 771218, Steamboat Springs, Colorado, 80477 ("Customer" or "Yampa Valley") made and entered into on this 11th day of April, 2012, amends and restates the Power Purchase Agreement entered into on April 15, 1992, as it has been amended (the "Prior Agreement"). Public Service and Customer are sometimes referred to collectively as the Parties ("Parties") and each individually as a Party ("Party").

WITNESSETH:

WHEREAS, Public Service is a public utility engaged in, among other services, the generation, transmission and distribution of electric power and energy; and

WHEREAS, Customer is a cooperative electric association engaged in the transmission and distribution of electric power and energy to its members and consumers; and

WHEREAS, Customer desires to purchase from Public Service and Public Service desires to sell to Customer Full Requirements Service, as defined herein, in excess of Customer's Western Preference Power and Customer Eligible Renewable Purchased Power, as each such term is defined herein, for the term, at a price and upon the terms and conditions set forth herein;

NOW THEREFORE, in consideration of the premises, covenants and agreements hereinafter set forth, the Parties hereby agree as follows:

ARTICLE I
DEFINITIONS

1.1 "**Agreement**" shall mean this Amended and Restated Power Supply between Public Service and Customer including all exhibits and rate schedules together with all appendices and attachments which are attached hereto and made a part hereof, and any amendments thereto. This Agreement is an agreement pursuant to Public Service's Assured Power and Energy Requirements Service Tariff on file with the FERC, and as such shall be subject to all terms and conditions of service set out in the Tariff, as it may be amended from time to time.

1.2 "**Assured Power and Energy Requirements**" shall mean Customer's Total Power and Energy Requirements in excess of Customer's Western Preference Power and Customer Eligible Renewable Purchased Power.

1.3 "**Authorized Operating Representatives**" shall mean the persons described in Article XI hereof.

1.4 **"Customer Eligible Renewable Purchased Power"** shall mean renewable power and associated energy purchased under contracts with third parties that in the aggregate, for any given hour during the term of this Agreement, may be the higher of 1.25 MW, one percent (1%) of the Customer's hourly peak demand during the year preceding the date on which the contract(s) is executed, or the amount that is necessary to satisfy the requirements for scheduling energy onto the Public Service system.

1.5 **"FERC"** shall mean the Federal Energy Regulatory Commission or any successor regulatory agency with jurisdiction over the transactions covered by this Agreement.

1.6 **"Full Requirements Service"** shall mean capacity and associated energy provided by Public Service in accordance with Rate Schedule A to this Agreement to meet Customer's total electric system requirements in excess of Customer's Western Preference Power and Customer Eligible Renewable Purchased Power.

1.7 **"Law"** shall mean any federal, state or local statute, act, ordinance, rule or regulation, and any decree, resolution, directive, order, authorization or code having the force of law and any binding judicial or administrative interpretation thereof, as enacted, including amendments, modifications, extensions, replacements or re-enactments thereof.

1.8 **"Moody's"** shall mean Moody's Investors Service Inc. or its successor.

1.9 **"Partial Requirements Service"** shall mean such purchases of power and energy as Customer shall make from Public Service when Customer has exercised its option under Exhibit C to terminate Full Requirements Service and obtain power and energy from sources other than Public Service and the other sources specified in Section 1.13.

1.10 **"Performance Assurance"** shall mean cash deposited in an interest bearing escrow account where the Requesting Party is designated as beneficiary; an irrevocable standby letter of credit (in a form and from an institution acceptable to the Requesting Party in its reasonably exercised discretion); a corporate guaranty from a creditworthy entity that is reasonably acceptable to the Requesting Party; or other form of credit support that is reasonably acceptable to the Requesting Party.

1.11 **"Points of Delivery"** shall mean those locations identified on Exhibit B where the Customer's Assured Power and Energy Requirements are delivered by Public Service to Customer.

1.12 **"Total Power and Energy Requirements"** shall mean the power and energy necessary to meet Customer's entire electric system power and energy requirements during the term of the Agreement.

1.13 **"S&P"** shall mean Standard & Poor's Rating Group (a division of McGraw-Hill Inc.) or its successor.

1.14 **"Western"** shall mean the Western Area Power Administration, a federal agency, or any successor organization.

1.15 **"Western Preference Power"** shall mean the allocations of firm power and energy that Customer has the right to receive, as identified on Exhibit A to the Agreement.

ARTICLE II
TERM AND REGULATORY APPROVAL

2.1 **Effective Date.** This Agreement will become effective on the date on which it has been accepted for filing by the FERC, subject to Sections 2.4 and 2.5.

2.2 **Initial Term.** This Agreement shall continue in effect for an initial term through 2400 hours Mountain Time, April 15, 2042, and thereafter until terminated by either Party upon no less than five (5) years' prior written notice to the other Party; provided, however, that any such notice given by Customer cannot be effective prior to April 15, 2037. Public Service has an option to terminate this agreement at any time beginning April 15, 2040 with a 5 year prior notice. Any notice given by Public Service cannot be effective prior to April 15, 2035.

2.3 **General Obligations.** It is recognized by the Parties that each Party requires certain approvals by regulatory agencies or commissions to consummate and implement this Agreement. A Party may require certain permits, approvals, or authorizations by various agencies having jurisdiction in order for that Party to perform its obligations pursuant to this Agreement. Each Party agrees to cooperate with the other Party in securing the necessary approvals required under this Agreement.

2.4 **FERC.** Public Service shall file this Agreement, as amended, with FERC within sixty (60) days of execution by the Parties or, in the alternative, as part of the settlement in Docket No. ER11-2853-000. Customer shall file a letter of concurrence or comments, as appropriate, supporting such filing by Public Service. If FERC does not issue an order accepting the Agreement for filing in its entirety and without material change, the Parties shall negotiate the terms necessary to comply with the FERC order and provide benefits to both Parties similar to those established by the Agreement. The Agreement shall not take effect pending agreement by the Parties on such terms and acceptance for filing of the Agreement by the FERC.

2.5 **RUS Approval.** The provisions of this Agreement, including the attached exhibits and rate schedules, are subject to the approval of the Administrator of the United States Department of Agriculture Rural Utilities Service ("RUS"). Customer shall submit this Agreement to RUS within fifteen days of execution by the Parties and shall request any required approvals. This Agreement shall not take effect until RUS has either granted any necessary approvals or has otherwise determined that the Agreement is in compliance with RUS regulations.

ARTICLE III
CONDITIONS OF SERVICE

3.1 **Purchases.** During the term of this Agreement, Public Service shall sell and make available at the Points of Delivery and Customer shall purchase firm power and energy sufficient to meet all of Customer's Assured Power and Energy Requirements.

3.2 **Early Termination Options**. The Customer shall have an irrevocable option to terminate its purchases under this Agreement upon the terms and conditions set forth in Exhibit C attached hereto.

3.3 **Reserves**. Public Service shall not be obligated to provide reserves in excess of those necessary to support its sales of Assured Power and Energy Requirements to Customer under this Agreement.

3.4 **Specifications of Power and Energy**. The electric power and energy to be sold by Public Service to Customer shall be delivered at transmission voltages in the form of three phase alternating current as specified for each Point of Delivery as set forth on Exhibit B. Changes in or additions to the Points of Delivery shall be made only upon mutual agreement of the Parties. The percent adjustment to account for losses between the Point of Delivery to Customer and the metering point shall be made to all power and energy metered as specified in Exhibit B. Said adjusted metered power and energy shall be considered to have been metered at the Points of Delivery to Customer.

ARTICLE IV
WESTERN PREFERENCE POWER AND CUSTOMER ELIGIBLE RENEWABLE PURCHASED POWER

4.1 **Monthly Schedules of Western Preference Power**. Customer shall be responsible for the submission of monthly schedules of the Western Preference Power, as identified in Exhibit A, in accordance with the provisions of Section 7.2. Public Service, at its discretion, and consistent with any applicable scheduling limitations imposed by Western, may change any schedule prepared by or for Customer in order to more efficiently meet Public Service's needs. In the event any such change in schedule is made during a month, Public Service shall reduce Customer's monthly billing demand and contribution to Public Service's monthly system peak demand by the full amount of the Western capacity available during that month, notwithstanding the fact that during those hours a lesser amount was actually scheduled.

4.2 **Changes in Western Preference Power**. Customer may take action to change its Western Preference Power and to propose a new Exhibit A, provided that any increase of Western Preference Power to Customer shall not be sought which reduces the annual amount of Assured Power and Energy Requirements which Customer has purchased from Public Service during the preceding calendar year.

4.3 **Transmission of Western Preference Power**. Customer shall be responsible for the transmission of Customer's Western Preference Power to the Points of Delivery under separate agreement. Customer shall request that Western contract with Public Service for such transmission service. Public Service shall participate and cooperate in making such transmission arrangements.

4.4 **Scheduling and Accounting of Customer Eligible Renewable Purchased Power**. Customer shall notify Public Service no later than one hundred twenty (120) days prior to initiating any purchase of Customer Eligible Renewable Purchased Power. Immediately

following such notification, Customer and Public Service shall establish such protocols as are necessary to schedule and account for energy associated with such purchases.

ARTICLE V
RATE

5.1 **Rate**. Customer shall pay for the Assured Power and Energy Requirements delivered hereunder at the rates, terms and conditions set forth in the rate schedule in effect from time to time with the FERC. The applicable rate schedule (Rate Schedule A) is attached hereto and made a part hereof. Customer's monthly charges shall be as calculated based upon the current effective Rate Schedule and the meter readings made monthly at each Point of Delivery.

5.2 **Change in Rate**. Either Party may unilaterally make application to the FERC requesting a change in rates under Section 205 or 206 of the Federal Power Act, as appropriate. Customer may oppose a rate increase filing made by Public Service. Prior to initiating any regulatory filing the purpose of which is to affect the rates, terms, or conditions of full requirements or partial requirements service rendered by Public Service to Customer under this Agreement, the affected parties shall first meet to discuss the nature of the filing, the changes sought, and to explore whether agreement as to proposed changes can be achieved prior to filing. If agreement cannot be achieved within 45 days, the Party proposing to seek the change may make the filing.

ARTICLE VI
BILLING

6.1 **Monthly Invoices**. Public Service shall prepare and submit to Customer monthly invoices for the power and energy delivered hereunder in each month reflecting the quantity of purchases derived from meter readings and the charges therefore based upon the rate schedule in effect. Monthly invoices shall be due and payable fifteen (15) days after being tendered. In the event that any day upon which payment is due shall not be a business day, such payment shall be made on the next succeeding day which is a business day. Payment shall be made by electronic funds transferred in immediately available funds to an account to be specified by Public Service.

6.2 **Disputed Payment**. Except as otherwise provided in the FCA Protocols attached to Public Service's Assured Power and Energy Requirement Service Tariff, in the event of a dispute between the Parties on the accuracy of any bill, Customer shall pay the full amount of the bill by the due date. The Parties shall promptly resolve the dispute, or if no resolution is reached within 60 days, shall arbitrate in accordance with Article XIV. Any adjustment required for any excess or deficiency in billing shall be made on the next monthly billing following the month of resolution of the dispute and shall include interest at an annual rate equal to the time-weighted average prime rate as established by Wells Fargo & Company or its successor, plus one percent calculated from date of payment to date of refund by credit on invoice. If Customer fails to make any payment required to be made hereunder within the time period specified, Customer shall pay, in addition to the amount of the required payment, a late charge consisting of interest upon the late payment at a rate of two percent over the time-weighted average prime rate as reported by Wells Fargo & Company or its successor calculated from the due date to and including the date of actual payment.

ARTICLE VII
FORECASTS AND SCHEDULES

7.1 **Annual Forecast**. By July 1 of each calendar year, Customer shall submit to Public Service a forecast of Customer's estimated Total Power Requirement for each Point of Delivery, and Total Energy Requirements for Customer's system, for each of the months of the following calendar year and for each summer and winter season for the following four years. In the event Customer becomes aware of any change in its load requirements which would render its forecast inaccurate by 5% or more, it shall submit to Public Service a revised forecast for the balance of that calendar year reflecting its new forecast.

7.2 **Monthly Western Schedules**. Customer shall be responsible for the submission to Public Service in each month the amount of Western Preference Power it has scheduled to be delivered from Western in the following month. Such schedule shall be transmitted to Public Service at least ten days before the first day of the month for which such schedules are applicable and shall reflect the scheduling of Western Preference Power and energy for each sixty minute interval in accordance with procedures established in advance by the operating representatives of the Parties.

7.3 **Other Information**. Public Service shall keep Customer fully informed of its policies and procedures with regard to scheduling of power sales and exchanges on the systems under its control. The Parties shall cooperate in the full exchange of such planning and operating information as may be reasonably necessary for timely and efficient performance of the Parties' obligations under the Agreement.

ARTICLE VIII
FACILITIES

8.1 **Service Continuity**. To the extent it has responsibility for doing so, Public Service shall use reasonable diligence in accordance with prudent utility practice to properly operate and maintain the facilities necessary to meet its obligations to deliver power and energy under this Agreement to the Points of Delivery to minimize interruption of deliveries hereunder. Nevertheless, Public Service cannot guarantee transmission and transformation services against interruption due to scheduled maintenance and repair outages or uncontrollable forces. Public Service shall make no adverse distinction in the continuity or the quality of the service it provides to Customer and the continuity and quality of the service that it provides to its retail customers.

8.2 **Delivery Facilities**. Each Party shall make a sufficient space available in its facilities at the Points of Delivery to accommodate the installation of the meters and metering equipment and any other facilities which the other Party may be required to install in order to carry out the deliveries of power and energy and other terms of this Agreement. Each Party grants and conveys to the other Party, its employees, agents, contractors and subcontractors a license to enter its facilities and rights-of-way as necessary to meet its obligations, including reading and maintaining meters and inspecting, maintaining, repairing, or replacing other facilities at the Points of Delivery; provided, however, that the Parties shall keep each other apprised of such entries in accordance with operating procedures to be established.

8.3 **Facilities Provided by Public Service**. Public Service shall provide and maintain all system facilities on the supply side of the Points of Delivery, located as set forth herein, as necessary to supply of service. Public Service shall provide suitable meter and metering equipment at a location satisfactory to Public Service on a site provided by Customer at each Point of Delivery.

8.4 **Facilities Provided by Customer**. Customer shall supply at its expense, or contract with others to provide, the necessary step down substations, including necessary switch gear and protective devices and a suitable location for Public Service's meters and metering equipment at each Point of Delivery.

ARTICLE IX
POWER FACTOR

Customer shall be required to maintain at all times a power factor between ninety five percent (95%) leading and ninety-five percent (95%) lagging at each Point of Delivery. If Customer fails to maintain the power factor as required by this Article, then Public Service may take whatever corrective measures it deems necessary and Customer may be billed for the full cost of the corrective action.

ARTICLE X
RELATIONSHIP OF THE PARTIES

Nothing herein contained shall be construed to create an association, joint venture, trust, or partnership between the Parties.

ARTICLE XI
AUTHORIZED OPERATING REPRESENTATIVES

The Parties shall appoint Authorized Operating Representatives to administer this Agreement. The Authorized Operating Representatives are hereby authorized and shall be responsible to establish, review, approve, and/or modify procedures and standard practices, consistent with the provisions hereof, as set forth in this Agreement.

For Public Service:

Manager, Wholesale Account Management
Xcel Energy
1800 Larimer Street, Suite 1000
Denver, Colorado 80202
Telephone: (303) 571-2732
Facsimile: (303) 294-2913

Wholesale Account Manager
Xcel Energy
1800 Larimer Street, Suite 1000
Denver, Colorado 80202
Telephone: (303) 571-7733
Facsimile: (303) 294-2913

For Customer:

General Manager
Yampa Valley Electric Association, Inc.
P.O. Box 771218
Steamboat Springs, Colorado 80477

Any change in the Authorized Operating Representatives shall be provided to the other Party in writing.

ARTICLE XII
NOTICES

All communications and notices provided for in this Agreement, unless otherwise noted, shall be given as follows:

To Public Service:

Manager, Wholesale Account Management
Xcel Energy
1800 Larimer Street, Suite 1000
Denver, Colorado 80202
Telephone: (303) 571-2732
Facsimile: (303) 294-2913

Wholesale Account Manager
Xcel Energy
1800 Larimer Street, Suite 1000
Denver, Colorado 80202
Telephone: (303) 571-7733
Facsimile: (303) 294-2913

To Customer:

General Manager
Yampa Valley Electric Association, Inc.
P.O. Box 771218
Steamboat Springs, Colorado 80477

The Parties may change the persons to whom notices are addressed, or their addresses, by providing notice thereof as specified this Article.

ARTICLE XIII
CHANGES IN CHARGES AND TERMS AND CONDITIONS OF SERVICE

The Parties intend that this Agreement may be changed only by a written amendment executed by both Parties; provided that Public Service may, at any time and from time to time, and subject to the limitations of this Agreement, unilaterally make application to the FERC for changes in the rates, charges, and loss provisions provided in the attached service schedules, or any substitute or successor thereto, under Section 205 of the Federal Power Act and pursuant to the FERC's Rules and Regulations promulgated thereunder, and Customer shall be free to oppose any such changes, or to seek modification of such specified provisions of this Agreement under the appropriate section(s) of the Federal Power Act.

ARTICLE XIV
ENVIRONMENTAL COSTS AND EMISSIONS ALLOWANCES

In the event that any Law requires Public Service or Customer to take action to reduce, rehabilitate or abate any actual, alleged or potential environmental harm including, but not limited to, (a) requiring reduction of greenhouse gases, SO2, NOx, mercury, particulate matter or any other emissions; or (b) imposing on Public Service or Customer the obligation to acquire, hold or surrender carbon dioxide or other emission allowances or equivalent emission rights under a cap and trade or other market-based emission reduction program and such Law imposes additional costs on either Public Service or Customer associated with the electric service provided by Public Service to Customer under this Agreement, Public Service and Customer's Authorized Operating Representatives and such other subject matter experts as each Authorized Operating Representative desires shall meet to address and recommend to the management of the Parties how this Agreement, including the pricing provisions thereof, should, if necessary, be equitably modified to take into account the effect and associated costs of such Law.

In considering whether modification of this Agreement is necessary, the Parties agree to apply the following principles:

(1) it is appropriate for Public Service to recover, as part of its cost of service and through the rates for services under this Agreement, appropriately allocable costs of installing, owning and operating emission controls or plant modifications mandated by such Law;

(2) it is appropriate for Public Service to recover, as part of its cost of service and through the rates for services under this Agreement, the appropriately allocable costs of

acquiring such allowances that are necessary for Public Service to be in compliance with such Law;

(3) to the extent that Public Service as a retail service provider is granted emissions allowances by virtue of its service to retail load, it will be appropriate for Company to apply those allowances or credits solely to its retail service;

(4) to the extent that Public Service as a wholesale service provider is granted emissions allowances by virtue of its service to Customer, it will be appropriate for Company to apply those allowances or credits solely for the benefit of Customer.

To the extent Customer is allocated emissions allowances or credits by virtue of its own retail load, Public Service and Customer shall include in any discussion of possible modifications that need to be made to this Agreement whether (given the circumstances and conditions of the allocation of allowances or credits to Customer) Customer shall provide or otherwise make available those allowances or credits to Public Service at the request of Public Service, to offset, in whole or in part, the allowances or credits that Public Service would otherwise need to continue to provide service to Customer.

Notwithstanding anything to the contrary in this Agreement, including the rate attachments hereto, in the event that the Parties are not able to reach agreement as to such modifications to this Agreement within sixty (60) days despite the exercise of good faith efforts to do so, each Party retains its rights to thereafter make a FERC filing under Section 205 or Section 206 of the FPA to address the issue.

ARTICLE XV
CREDITWORTHINESS

If a Party (the "Requesting Party") has commercially reasonable grounds to believe that the other Party's creditworthiness or financial performance under this Agreement has become unsatisfactory, the Requesting Party may require the other Party (the "Second Party") to provide Performance Assurance, or some other mutually agreeable method of satisfying the creditworthiness or financial performance concerns of the Requesting Party; provided, however, that the Requesting Party may only request, and the Second Party shall only be required to provide, Performance Assurance for the following amounts: (i) amounts due and owing, including any amounts in dispute for which payment may have been withheld, in accordance with this Agreement, and (ii) amounts reasonably projected to become due and owing for services to be provided pursuant to this Agreement during the sixty (60) day period following such request.

Events that may cause PSCo, as the Requesting Party, to question the creditworthiness of Customer or its ability to financially perform, as the Second Party, include, but are not limited to, the following:

a) Customer is failing to financially perform or in financial default under other material contracts;

b) Customer has defaulted or otherwise failed to perform under its loan agreements or other financing arrangements;

c) Customer, has debt outstanding that is rated by S&P or Moody's and the credit rating for that debt is below BBB- or Baa3 by S&P or Moody's, respectively; or

d) Customer has experienced other material adverse changes in its financial condition that, using reasonable business judgment, has the likelihood of affecting its ability to financially perform under this Agreement.

Events that may cause Customer, as the Requesting Party, to question the creditworthiness of PSCo or its ability to perform, include, but are not limited to, the following:

a) PSCo is failing to financially perform or is in financial default under other material contracts;

b) More than fifty percent (50%) of PSCo's owned generation assets are sold, assigned or otherwise transferred to another legal entity not directly owned or otherwise under the legal control of PSCo;

c) PSCo has debt outstanding that is rated by S&P or Moody's and the credit rating for that debt is below BBB- or Baa3 by S&P or Moody's, respectively; or

d) PSCo has experienced other material adverse changes in PSCo's financial condition that, using reasonable business judgment, has the likelihood of affecting its ability to perform under this Agreement.

If the Second Party fails to provide Performance Assurance within ten (10) Business Days of demand therefore, such failure will be considered an Event of Default (as that term is defined in Article XVI) under this Agreement and the Requesting Party shall have the right to exercise any of the remedies provided for under this Agreement or as may otherwise be available at law or in equity. Nothing contained in this Section shall affect any credit agreement or arrangement, if any, between the Parties. At such time as the event causing the Requesting Party to question the creditworthiness of the Second Party, as set forth above, ends or is cured, and no new event has arisen that causes the Requesting Party to question the creditworthiness of the Second Party, the Performance Assurance previously provided by the Second Party shall be withdrawn.

ARTICLE XVI
EVENTS OF DEFAULT; REMEDIES

An "Event of Default" shall mean, with respect to a Party (a "Defaulting Party"), the occurrence of any of the following:

a) the failure to make, when due, any uncontested payment required pursuant to this Agreement if such failure is not remedied within five (5) Business Days after receiving written notice from the non-Defaulting Party;

b) any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated and such default remains uncured and impairs the ability of the Party to perform its obligations under this Agreement;

c) the failure to perform any material covenant or obligation set forth in this Agreement, if such failure is not remedied within fifteen (15) Business Days after receiving written notice from the non-Defaulting Party, or such longer time as is reasonably necessary to cure such default provided both that such Party is acting diligently and in good faith to cure such default and that the non-Defaulting Party agrees in writing to such longer time period for Defaulting Party to cure such default;

d) such Party becomes the subject of Bankruptcy Proceedings;

e) the failure of such Party to satisfy the Performance Assurance requirements set forth in Article XV, Creditworthiness, above or the terms and conditions of such Performance Assurance;

f) such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another entity and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee entity fails to assume all the obligations of such Party under the Agreement to which it or its predecessor was a party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party; or

g) the occurrence and continuation of (i) a default, event of default or other similar condition or event in respect of such Party under one or more agreements or instruments, individually or collectively, relating to indebtedness for borrowed money in an aggregate amount of not less than $5,000,000, which results in such indebtedness becoming, or becoming capable at such time of being declared, immediately due and payable or (ii) a default by such Party in making on the due date therefore one or more payments, individually or collectively, in an aggregate amount of not less than $5,000,000.

Upon the occurrence of an Event of Default, the first Party to become aware of the Event of Default shall immediately notify the other Party of the occurrence of the Event of Default.

Except for those Events of Default set forth in subsections (a), (c) and (e) above, for which a specified cure period is identified, and except for an occurrence wherein a Party becomes the subject of Bankruptcy Proceedings as set forth in subsection (d) above, the following time frames shall apply with respect to a Defaulting Party's right to cure the Event of Default. If the Defaulting Party is the first to become aware of the Event of Default, the Defaulting Party shall have thirty (30) Business Days from the occurrence of the Event of Default to cure. If the non-defaulting Party is the first to become aware of the Event of Default, the Defaulting Party shall have thirty (30) Business Days from the receipt of the notice of default to cure. The Parties specifically agree that they shall be obligated to negotiate with each other in

good faith during the time period for cure in an attempt to resolve the issues which gave rise to the Event of Default. Notwithstanding the foregoing, in the event of a monetary default or the uncontested failure to deliver energy, the non-Defaulting Party may, by written notice to the Defaulting Party, immediately withhold and/or suspend deliveries or payments if the Event of Default is not cured within the specified period or, in the case of Bankruptcy, to take such action(s) immediately upon the occurrence of such Event.

ARTICLE XVII
UNCONTROLLABLE FORCE AND INDEMNIFICATION

17.1 **Uncontrollable Force.** Neither Party to this Agreement shall be considered to be in default in performance of any obligation hereunder if failure of performance shall be due to an Uncontrollable Force. The term "Uncontrollable Force" means any cause beyond the control of the Party affected, including, but not limited to, failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, and restraint by court order or public authority, which by exercise of due foresight such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to overcome. A Party shall not, however, be relieved of liability for failure or performance if such failure be due to causes arising out of its own negligence or to removable or remediable causes which it fails to remove or remedy with reasonable dispatch. Any Party rendered unable to fulfill any obligation by reason of an Uncontrollable Force shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein, however, shall be construed to require a Party to prevent or settle a strike against its will.

17.2 **Indemnification.** Each Party shall save and hold harmless the other Party, its officers, employees and agents from any and all Claims for injury to person or persons or damage to property occurring on its respective side of the Point of Delivery, including claims made by customers of due to interruptions or failures in providing electric service.

ARTICLE XVIII
LIMITATION OF LIABILITY

IN NO EVENT SHALL EITHER PARTY, ITS AFFILIATES OR ITS REPRESENTATIVES BE LIABLE FOR ANY LOST OR PROSPECTIVE PROFITS OR ANY OTHER SPECIAL, PUNITIVE, EXEMPLARY, CONSEQUENTIAL, INCIDENTAL, OR INDIRECT LOSSES OR DAMAGES (IN TORT, CONTRACT OR OTHERWISE) UNDER OR IN RESPECT TO THIS AGREEMENT.

ARTICLE XIX
WAIVER

Any waiver by a Party of its rights with respect to default hereunder, or with respect to any other matter arising in connection herewith, shall not be deemed to be a waiver with respect to any subsequent default or matter.

ARTICLE XX
ARBITRATION

Except for those disputes related to fuel clause calculations that the parties have agreed are to be resolved pursuant to the FCA Protocols attached as part of the Assured Power and Energy Requirements Tariff, any controversy involving this Agreement may be submitted to arbitration upon mutual agreement of both Parties. Absent such agreement, disputes shall be referred to the FERC or other appropriate regulatory or judicial body. If arbitration is selected, the Parties shall agree upon appointment of a single arbitrator. If the Parties fail to agree upon a single arbitrator, Public Service or Customer may within twenty (20) days thereafter request the American Arbitration Association to appoint an arbitrator. The arbitrator so appointed shall afford each of the Parties an opportunity to conduct discovery and to be heard, and shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association. The arbitrator shall consider and decide the controversy and notify the Parties in writing of his decision and the reasons therefore, and shall make an award relative to the payment of costs and expenses of arbitration. The arbitrator shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change this Agreement in any manner, except as agreed by the Parties. The decision of the arbitrator shall be binding upon the Parties. Submission to arbitration shall be made, and the award may be reported to the appropriate court and shall be enforceable in accordance with applicable statutes.

ARTICLE XXI
ENTIRE AGREEMENT

This Agreement constitutes the entire agreement of the Parties hereto with respect to the transaction addressed herein. Notwithstanding the foregoing, it is understood that the this Agreement is an agreement pursuant to Public Service's Assured Power and Energy Requirements Service Tariff on file with the FERC, and that such Tariff sets forth additional terms and conditions that apply to the Agreement.

ARTICLE XXII
COUNTERPARTS

This Agreement may be executed in any number of counterparts. All such counterparts shall be deemed originals and shall constitute but one and the same instrument.

ARTICLE XXIII
ASSIGNMENT

This Agreement shall be binding upon and inure to the benefit of Public Service and Customer and their respective successors and assigns.

Neither Party shall assign this Agreement without the prior written consent of the other Party, which consent shall not be unreasonably withheld, except as follows:

- to mortgage, create or provide for a security interest in or convey in trust all or part of its interest herein to a trustee or trustees under a deed of trust or company-

wide indenture (including all assets), or to a mortgagee under a mortgage, or to secured parties under a security agreement;

- to any corporation into which or with which the Party making the assignment is merged or consolidated or to which the Party transfers substantially all of its assets;
- to any person or entity wholly owning, wholly owned by, or wholly owned in common with the Party making the assignment;
- in the case of Customer, to the United States of America pursuant to the provisions of Customer's loan agreement with the United States of America; or
- in the case of Customer, to an entity that Customer and Holy Cross owns or controls.

No assignment, merger or consolidation shall relieve any Party of its obligations under this Agreement or impose additional obligations or burdens on the other Party unless specifically so agreed in writing by the other Party.

ARTICLE XXIV
AMENDMENT; SEVERABILITY

This Agreement may not be amended, modified or otherwise altered in any manner except in writing signed by Public Service and Customer, except as specifically provided for herein. Except as otherwise expressly provided herein, no amendment of this Agreement shall affect the validity or enforceability of any other agreement to which Customer and Public Service are a party. In the event that any provision in this Agreement is declared illegal or no longer in force by reason of any judgment or order issued by a court or regulatory body of competent jurisdiction, all remaining provisions of this Agreement not affected by such judgment or order shall continue in full force and effect. The parties shall use best efforts to renegotiate any section of this Agreement held invalid or illegal, and which shall reflect the original intent of the parties.

ARTICLE XXV
GOVERNING LAW

This Agreement shall be subject to and be construed according to the laws of the State of Colorado and where applicable, the Federal Power Act.

IN WITNESS WHEREOF, on the date set forth above, the Parties hereto have caused this Agreement to be executed in their respective names by their authorized representatives.

PUBLIC SERVICE COMPANY OF COLORADO,
a Colorado corporation

By: _____
Name: David L. Eves
Title: President and CEO
Public Service Company of Colorado

YAMPA VALLEY ELECTRIC ASSOCIATION, INC.,
a Colorado cooperative electric association

By: _____
Name: Lawrence D. Covillo
Title: President and General Manager

EXHIBIT A

WESTERN PREFERENCE POWER

This Exhibit A is part of the Amended and Restated Power Purchase Agreement (the "Agreement") and shall remain in effect as part of the Agreement unless and until superseded by a new Exhibit A; provided, that this Exhibit A or any superseding Exhibit A shall terminate at the expiration of this Agreement.

The following outlines the allocation of firm power and energy from the Western Salt Lake City Areas Integrated projects which is available to Customer.

After September 30, 2004:

Maximum Monthly Capacity - Contract Rate of Delivery (CROD)

Winter Season	5024 kW
Summer Season	4663 kW

Energy

Customer can schedule energy up to 100% of its monthly CROD using Available Hydro Power, Western Replacement Power and/or Customer Replacement Power.

Western will deliver power and energy to specified points of interconnection between Customer and Western.

EXHIBIT B

POINTS OF DELIVERY
OF
YAMPA VALLEY ELECTRIC ASSOCIATION

This Exhibit B is part of the Amended and Restated Power Purchase Agreement (the "Agreement") and shall remain in effect as part of the Agreement unless and until superseded by a new Exhibit B; provided, that this Exhibit B or any superseding Exhibit B shall terminate at the expiration of this Agreement.

Point of Delivery	Delivery Voltage KV	Metering Voltage KV	Low Side Metering Adjustment %
Mt. Harris	69	69	0.00
Craig Transfer	69	69	0.00
Steamboat	69	69	0.00
Stagecoach	12.5	12.5	0.00
Craig Transfer TSGT Warehouse	230	13.8	0.13

EXHIBIT C

EARLY TERMINATION OPTION

Customer may convert any point(s) of delivery served under this Agreement to Partial Requirements Service, with such service to commence no earlier than January 1, 2025. If Customer elects to convert to Partial Requirements Service, it shall give Public Service notice of the Point(s) of Delivery which will be converted to Partial Requirements Service, and the amount by which it proposes to reduce its Full Requirements Service purchases from Public Service. The notice required shall be a function of the proposed level of reduction of total load supplied by Public Service in accordance with the following schedule:

Minimum Notice	Percent of Maximum Load Reduction
12 Months	20%
24 Months	40%
36 Months	60%
48 Months	80%
60 Months	100%

If Customer elects to convert to Partial Requirements Service, Public Service shall make available to Customer a Partial Requirements Service rate. If the Parties cannot agree on the appropriate Partial Requirements Service rate, Public Service shall make the appropriate filing with the FERC seeking implementation of a Partial Requirements Service rate, and Customer shall have the right to contest such filing.

RATE SCHEDULE A

PUBLIC SERVICE COMPANY OF COLORADO

RATE FOR GENERATION SERVICE

TO YAMPA VALLEY ELECTRIC ASSOCIATION, INC.

The sale of electric power and energy by Public Service Company of Colorado ("Public Service" or "PSCo") to Yampa Valley Electric Association, Inc. ("Yampa") pursuant to the Amended and Restated Power Purchase Agreement (the "Agreement") shall be at the following rates, which are subject to modification as specified in Article V, Section 2 of the Agreement. These rates stated below are for generation services only; the rates for transmission and ancillary services necessary for Public Service to make deliveries of the power and energy that Yampa purchases under the Agreement are specified in another rate schedule to the Agreement. When Public Service's Assured Power and Energy Requirements Service Tariff (as it may be amended from time to time, the "Tariff") becomes effective, the rates for service to Yampa will be effective on the same date and will be as follows:

MONTHLY RATE

Service and Facility Charge per month:	The $ rate/month, updated annually pursuant to the formula rate (Attachment A) to the Tariff
Demand Charge: All kilowatts of billing demand, per kW	The $ rate per kW/month updated annually pursuant to the formula rate (Attachment A) to the Tariff
Energy Charge: All Kilowatt hours of billing energy, per kWh	The non-fuel energy charge plus the base fuel cost, updated annually pursuant to the formula rate (Attachment A) to the Tariff

Demand is billed on Yampa's aggregate 60 minute integrated peak load coincident to the Company's production peak.

The Energy Charge shall be adjusted in accordance with the Tariff, Attachment C ("PSCo Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause") (the "FCA").

The above rates are deemed to recover (i) costs that Public Service has incurred to voluntarily reduce emissions for air quality improvement in three of its coal-fired generating stations located in the Denver Metro area, pursuant to Colorado Revised Statutes §40-3.2-102, and (ii) costs that Public Service has and will incur to comply with the Colorado "Clean Air Clean Jobs Act," Colorado Revised Statutes §§40-3.2-201 et seq..

If the Company renegotiates any of the contracts listed in the Tariff, Attachment C, Exhibit A ("Protocols for the Implementation of the PSCo Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause")(the "Protocols"), Schedule 1 with the result that payments that are eligible for inclusion in the FCA are increased and payments that are ineligible for inclusion in the FCA are decreased, the parties will negotiate an offsetting change in rates to avoid an over-recovery of costs, with each such offsetting change to be given effect concurrently with any increase in FCA charges that is attributable to the contract renegotiation.

The billing demand shall be based on the sixty-minute integrated kilowatt demand occurring simultaneously at the Customer's Points of Delivery coincident with Public Service's monthly peak load used for allocating demand costs during the month, when the metered simultaneous demands are adjusted for transformer losses to the Points of Delivery and decreased by the schedule for that interval of power purchased by Customer from Western and delivered at the Points of Delivery.

Notwithstanding other provisions of this Agreement, and if requested by Customer, Public Service will prepare the hourly schedule of Western Power as agent for Customer. If Customer accepts such schedule, the billing demand will be no greater than the difference between the simultaneous maximum measured demand at the Points of Delivery and the maximum monthly capacity provided by Western as adjusted for transmission losses. If the average monthly load factor of the Western Power as contained in Exhibit A changes materially from the average monthly load factor contained in the original Exhibit A to this Agreement or if Western imposes further constraints on the hourly schedules which inhibit Public Service's ability to achieve the required schedules, Public Service may, at its option, calculate the billing demand without regard to the obligations set forth in this paragraph.

The billing energy shall be the energy metered for that month at the Customer's Points of Delivery, adjusted for transformer losses to the Points of Delivery and decreased by the schedule of energy purchased by Customer from Western and delivered at the Points of Delivery. If during any sixty-minute interval, the energy scheduled from Western exceeds the metered energy for that interval, as adjusted for transformer losses, then such scheduled Western energy shall be reduced by such excess energy before determination of the energy to be billed by Public Service.

Commencing on the Rate Date, Customer shall be allowed to net meter Customer load in a manner that complies with the minimum requirements of state law which, as of January 1, 2010 imposes 10kW residential customer and 25 kW commercial minimum limits.

CREDITS

Beginning with January 1, 2011 through August 31, 2011, if the Company has recognized positive Generation Book Net Margins ("Gen Sale Margins") for these eight months of 2011

("2011 Partial Year Margin Allocation"), Company shall share with Customer in the following calendar year, as a credit to charges for firm wholesale requirements service, a 50% portion of such positive margins. The credit for the 2011 Partial Year Allocation and for the subsequent periods addressed in the immediately following paragraph shall be calculated by multiplying the Company's Gen Sale Margins during the period for which Gen Sale Margins are being allocated ("Period of Determination") times the Customer's total actual firm energy purchases from Company during the Period Determination divided by the aggregate value (in MWh) for Sales (S) used in setting monthly adjustments to energy billings for the months during the Period of Determination in accordance with the FCA. The credit in dollars shall be applied to the invoice for service in the month of March next succeeding the applicable calendar year. Gen Sale Margins are the margins from all Gen Sales, as that term is defined in the Protocols for the Implementation of the FCA. The margins are calculated as the difference between the sum of the revenues received from Gen Sale transactions during the Period of Determination minus the costs attributed to such Gen Sales during the Period of Determination in accordance with the Protocols. Such costs may include, among others, start-up costs, variable operating and maintenance expenses, and the costs of fuel, purchased power, transmission delivery and ancillary services, and displacement transactions.

Beginning with the partial period September 1, 2011 through December 31, 2011 and every calendar year thereafter, the Gen Sale Margin sharing will be aligned with the approved sharing of Gen Sale Margins in effect for the PSCo retail customers with the exception that no threshold for recovery of O&M costs will apply at wholesale because such costs are included in the formula rate set out in Attachment A of the Tariff. As of September 1, 2011, such retail sharing is 80% to customers and 20% to the Company. The method set out in the preceding paragraph shall be used to calculate the Gen Sale Margins and the Customer's margin sharing credit shall be based on the margin sharing percentage in effect during each calendar year. If the margin sharing percentage changes one or more times during a calendar year, the margin sharing credit shall be calculated for each Period of Determination and the annual margin sharing credit will be the sum of margin sharing credits for each Period of Determination. The margin sharing credit will be made annually and shown as a line item on Customer's March invoice.

RATE MORATORIUM

A. The parties agree that there shall be a Rate Moratorium period that begins on September 1, 2011 and ends on August 31, 2013 ("Rate Moratorium"). Except in the circumstances identified in B below, neither Party shall exercise any right under Sections 205 or 206 of the Federal Power Act to propose any modification to Attachment A of the Tariff, as it applies to Customer, to take effect prior to the end of the Rate Moratorium. During the Rate Moratorium, Public Service's return on equity shall be 10.4%.

B. The Rate Moratorium shall not apply to Section 205 filings that Public Service may file in the following circumstances:

(i) to request a shorter amortization period of early retirement costs of assets retired pursuant to the Clean Air Clean Jobs Act ("CACJA") (1) if industry accounting standards applicable to regulatory assets (*e.g.*, Financial Accounting Standards Board) change from the accounting standards in effect September 1, 2011, or (2) if the Colorado Public Utilities

Commission ("CPUC") orders a shorter amortization period for the retail portion of the early retirement costs of assets retired pursuant to the CACJA;

(ii) an annual filing to update expenses for formula rate input for Post Retirement Employee Benefits ("PBOP");

(iii) to align the depreciation rates in Attachment A of the Tariff with depreciation rates approved by the CPUC;

(iv) to make technical and clerical changes to Attachment A of the Tariff discussed with, and agreed to, by the Customer;

(v) to identify and quantify in Attachment A of the Tariff, and thereby seek recovery of, acquisition premiums that Public Service may pay as part of the purchase price for generation facilities that Public Service may acquire or seek to acquire as system resources to serve its customers;

(vi) to modify Attachment A of the tariff to recover the costs addressed in Article XV of the Agreement; or

(vii) to implement any most favored nation terms as agreed to by the Parties, as set out in such provision in the settlement of Docket No. ER11-2583-000.

Customer reserves its rights to contest or oppose any such filings.

Public Service Company of Colorado

WHOLESALE FUEL COST AND ECONOMIC PURCHASED POWER ADJUSTMENT CLAUSE

Yampa Valley shall be subject to Public Service's Assured Power and Energy Requirements Service Tariff, Attachment C ("PSCo Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause"), as it may be amended from time to time.

PROTOCOLS FOR THE IMPLEMENTATION OF THE PSCO WHOLESALE FUEL COST AND ECONOMIC PURCHASED POWER ADJUSTMENT CLAUSE (FCA)

In implementing Public Service's Assured Power and Energy Requirements Service Tariff, Attachment C ("PSCo Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause"), Public Service shall apply the "Protocols for the Implementation of the PSCo Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause," which is included as Exhibit A thereto, as they may be amended from time to time.

PUBLIC SERVICE COMPANY OF COLORADO

RATE FOR TRANSMISSION AND ANCILLARY SERVICES

TO YAMPA VALLEY ELECTRIC ASSOCIATION, INC.

In accordance with the terms of the Power Purchase Agreement as amended between Public Service Company of Colorado ("Public Service") and Yampa Valley Electric Association, Inc. ("Yampa Valley") (collectively, "Parties"), Yampa Valley purchases power and energy from Public Service. The Wholesale Merchant Function of Public Service has arranged with the Transmission Function of Public Service under the applicable Public Service transmission tariff for network transmission service and associated ancillary services to make deliveries of the power and energy to be supplied under the Power Purchase Agreement with Yampa. Yampa agrees to pay Public Service for the arranged transmission and ancillary services as follows:

Payment For Network Transmission Service

Future Changes to Network Integration Transmission Service: Payment for Network Integration Transmission Service shall be governed by Sections 1.0 through 1.1 below, but in the event that the Federal Energy Regulatory Commission ("Commission") approves any changes to the Transmission Provider's OATT, the OATT as changed will govern.

1.0 Monthly Demand Charge: The Network Customer shall pay a monthly Demand Charge, based on the monthly rate calculated using the formula included in Attachment O, page 1, line 17 in the Transmission Provider's OATT on file with the Commission. The rate is recalculated each year, effective June 1, based on the data for the prior year. Each month the Network customer shall pay the Transmission Provider the product of the monthly rate and the Transmission Customer's Monthly Network Load.

1.1 Determination of Network Customer's Monthly Network Load: The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider) coincident with the Transmission Provider's Monthly Transmission System Peak. All capacity quantities used in developing the Network Customer's Monthly Network Load shall be adjusted to the transmission system input level, i.e., shall include the transmission capacity amount associated with any applicable losses.

Ancillary Transmission Services Charges

2.0 Customer shall pay for Ancillary Transmission Services determined in accordance with the Transmission Provider's then effective OATT, as follows:

Schedule 1 - Scheduling, System Control and Dispatch Service
Schedule 2 - Reactive Supply and Voltage Control from Generation Sources Service
Schedule 3 - Regulation and Frequency Response Service
Schedule 5 - Operating Reserve - Spinning Reserve Service
Schedule 6 - Operating Reserve - Supplemental Reserve Service

Modification

3.0 It is the intent of the Parties that the transmission and ancillary service rates contained herein shall track the rates set forth in the open access transmission tariff applicable to the use of the Public Service transmission system ("Public Service Tariff"). Accordingly, nothing contained in this rate schedule shall be construed as affecting the right of either Party to unilaterally make application to the Commission for a change in rates and charges, classification of service, or any provision, term, rule, regulation, condition, or contract relating to such matters under sections 205 or 206 of the Federal Power Act and the Commission's Rules and Regulations promulgated thereunder.

If the Xcel Energy Operating Companies file with the Commission and secure Commission approval to change the transmission and ancillary service rates under the Public Service Tariff, such revised rates shall become effective with respect to Customer under this Agreement on the same date as the Commission permits the changed transmission and ancillary service rates under the Public Service Tariff to become effective.

APPENDIX A

[RESERVED]

APPENDIX B-1

RENEWABLE ENERGY CERTIFICATE RIDER (AMENDED)

This Renewable Energy Certificate Rider (Amended) ("REC Rider") is by and between Public Service Company of Colorado, a Colorado corporation, 1800 Larimer Street, Denver, Colorado 80202 ("Public Service") and Yampa Valley Electric Association, Inc. ("Yampa Valley"). Public Service and Yampa Valley are collectively referred to as Parties ("Parties"), and individually as a Party ("Party").

This REC Rider is a part of the Amended and Restated Power Purchase Agreement ("PPA") and shall be effective upon execution of the Amended and Restated Energy Credit Ownership Agreement ("REC Ownership Agreement") which is attached to the PPA as Appendix B-2. Under Colorado law, Yampa Valley is entitled to receive, from Public Service, Renewable Energy Certificates ("RECs") from certain renewable energy resources (referred to as "Designated Eligible Energy Resources") provided that it pays Public Service the full costs associated with Public Service's acquisition of energy and RECs from the Designated Eligible Energy Resources, including REC management costs. The REC Ownership Agreement sets forth the terms and conditions governing the transfer of a load ratio share of the RECs from Designated Eligible Energy Resources to Yampa Valley. This REC Rider sets out the mechanism whereby Yampa Valley will compensate Public Service for the full costs associated with its load ratio share of the Designated Eligible Energy Resources ("Incremental Cost for Yampa Valley") for the prior calendar year.

1. Public Service will calculate the Incremental Cost for Yampa Valley for the prior calendar year and provide the calculation and supporting information to Yampa Valley by May 1 of each year for the duration of the PPA. In consideration for the payment by Yampa Valley of the Incremental Cost for Yampa Valley, Public Service shall transfer RECs to Yampa Valley in accordance with Attachment B-2.

2. The Incremental Cost for Yampa Valley for the prior year shall be recovered through one REC Rider Charge to be applied to the May billing period in the year that follows the year for which the Incremental Cost for Yampa Valley was calculated.

3. The Incremental Cost for Yampa Valley shall be the sum of 1) the product of the Yampa Valley Load Ratio Share ("Yampa Valley LRS") and the Removed Costs for the prior calendar year; 2) the product of the Yampa Valley Wholesale Load Ratio Share ("Yampa Valley WLRS") and the REC Costs; and 3) the Appropriate Portion of Other Unrecovered Costs, as shown by the following formula:

   Incremental Cost for Yampa Valley = (Yampa Valley LRS) (Removed Costs) + (Yampa Valley WLRS) (REC Costs) + Appropriate Portion of Other Unrecovered Costs

   And where Removed Costs means the prior calendar year's costs of Designated Eligible Energy Resources that are uncollected by action of the economic screens set forth in the

Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause Protocols ("FCA Protocols") used to calculate the FCA;

And where the Yampa Valley WLRS shall be the quotient formed by the Energy Sales to Yampa Valley under the PPA divided by the Wholesale Load Energy, in each case for the same calendar year;

Yampa Valley WLRS = Energy Sales to Yampa Valley under PPA / Wholesale Load Energy

And where Wholesale Load Energy shall mean the total annual megawatt-hour energy sales made by Public Service to Wholesale Requirements Customers during the prior calendar year;

And where Wholesale Requirements Customers means those Public Service customers taking service under a FERC jurisdictional tariff or rate schedule that utilizes the FCA during the prior calendar year;

And where REC Costs means the Wholesale Requirements Customers' portion of the prior calendar year costs of administering, registering, certifying, acquiring, and transferring RECs;

And where Appropriate Portion of Other Unrecovered Costs means the Yampa Valley portion of all other costs associated with Designated Eligible Energy Resources that are not recovered by Public Service through base rates or the FCA during the prior calendar year that are reasonably attributable to Yampa Valley by specific assignment, by allocation using the Yampa Valley WLRS of costs attributable to Wholesale Requirements Customers, or by allocation using the Yampa Valley LRS of costs attributable to Public Service's customers.

And where all other terms are defined in the REC Ownership Agreement (Appendix B-2).

4. Within 120 days of the expiration of the PPA, Public Service shall calculate and provide Yampa Valley a bill for the Total Uncollected REC Rider Costs. Total Uncollected REC Rider Costs will be the sum of the uncollected portion of the REC Rider calculated in the prior calendar year (for costs incurred two years prior), if any, the Incremental Cost for Yampa Valley incurred in the prior calendar year, and the Incremental Cost for Yampa Valley incurred in the current calendar year to date. Yampa Valley will pay the Total Uncollected REC Rider Costs within thirty (30) days of mailing as determined by United States mail postmark.

5. The Incremental Cost for Yampa Valley for the current calendar year to date will be calculated in the same manner as the Incremental Cost for Yampa Valley for a prior calendar year (using information for the current calendar year from January 1 through the expiration date of the PPA.)

6. An example calculation of the REC Rider Charge for year 2020 follows:

Year for cost analysis = 2019, the prior calendar year

2019 Removed Costs = $0
2019 REC Costs = $20,000
2019 Appropriate Portion of Other Unrecovered Costs = $0

2019 Energy Sales to Yampa Valley Under PPA = 582,000 MWH
2019 Obligation Load Energy = 34,000,000 MWH
2019 Yampa Valley LRS = 582,000 / 34,000,000 = 1.71%
2019 Removed Cost for Yampa Valley = (1.71%) ($0) = $0

2019 Energy Sales to Yampa Valley Under PPA = 582,000 MWH
2019 Wholesale Load Energy = 5,500,000
2019 Yampa Valley WLRS = 582,000 / 5,500,000 = 10.58%
2019 REC Cost for Yampa Valley = (10.58%) ($20,000) = $2,116

2019 Incremental Cost for Yampa Valley = $0 + $2,116 + 0 = $2,116

2020 Year REC Rider = $2,116

7. An example calculation of the Total Uncollected REC Rider Costs to be collected in the period after PPA expiration follows:

PPA expires 4/15/2042; Final billing no later than 8/13/2042.

Total Uncollected REC Rider Costs = Uncollected portion of the REC Rider calculated in the prior calendar year (for costs incurred two years prior), if any, + Incremental Cost for Yampa Valley incurred in the prior calendar year + Incremental Cost for Yampa Valley incurred in the current calendar year to date.

Year for cost analysis for Uncollected portion of the REC Rider calculated in the prior calendar year = 20402040 Uncollected months of 2040 REC Rider = None (as of April 2042 billing period).

Uncollected portion of the REC Rider calculated in 2041 for 2040 = 0 Year for cost analysis for Incremental Cost for Yampa Valley for the prior calendar year = 2041

2041 Removed Costs = $2,000,000
2041 REC Costs = $100,000
2041 Appropriate Portion of Other Unrecovered Costs = $0

2041 Energy Sales to Yampa Valley Under PPA = 582,000 MWH
2041 Obligation Load Energy = 34,000,000 MWH
2041 Yampa Valley LRS = 582,000 / 34,000,000 = 1.71%
2041 Removed Cost for Yampa Valley = (1.71%) ($2,000,000) = $34,200

2041 Energy Sales to Yampa Valley Under PPA = 582,000 MWH
2041 Wholesale Load Energy = 5,500,000

2041 Yampa Valley WLRS = 582,000 / 5,500,000 = 10.58%
2041 REC Cost for Yampa Valley = (10.58%) ($100,000) = $10,580

2041 Incremental Cost for Yampa Valley = $34,200 + $10,580 + 0 = $44,780

Year for cost analysis for Incremental Cost for Yampa Valley for the current calendar year to date = 2042

2042 Removed Costs = $200,000
2042 REC Costs = $40,000
2042 Appropriate Portion of Other Unrecovered Costs = $0

2042 Energy Sales to Yampa Valley Under PPA = 220,000 MWH
2042 Obligation Load Energy = 11,200,000 MWH

2042 Yampa Valley LRS = 220,000 / 11,200,000 = 1.96%
2042 Removed Cost for Yampa Valley = (1.96%) ($200,000) = $3920

2042 Energy Sales to Yampa Valley Under PPA = 220,000 MWH
2042 Wholesale Load Energy = 2,222,222
2042 Yampa Valley WLRS = 220,000 / 2,222,222 = 9.9%
2042 REC Cost for Yampa Valley = (9.9%) ($40,000) = $3960

Uncollected REC Rider Costs for 2042= $3,920 + $3,960 + $0 = $7,880

Total Uncollected REC Rider Costs = $0 + $44,780 + $7,880 = $52,660

8. Removed Costs that have been recovered through application of this REC Rider are no longer eligible for recovery through subsequent application of the economic screens.

9. Either Party may terminate this REC Rider if the FERC subsequently conditions its approval or acceptance of the filing in any manner that such Party deems significant and adverse to it, or if the FERC upon subsequent complaint modifies this REC Rider in any manner that such Party deems significant or adverse to it.

APPENDIX B-2

AMENDED AND RESTATED RENEWABLE ENERGY CREDIT OWNERSHIP AGREEMENT

This Amended and Restated Renewable Energy Credit Ownership Agreement, hereinafter referred to as the "Agreement," is made and entered into as of April 11, 2012, by Yampa Valley Electric Association, Inc, a Colorado cooperative electric association, ("Yampa Valley"), whose mailing address is P.O. Box 771218, Steamboat Springs, Colorado, 80477 and Public Service Company of Colorado, a Colorado corporation, 1800 Larimer Street, Denver, Colorado 80202 ("PSCo" or Public Service"). Yampa Valley and Public Service may be referred to individually herein as a "Party" and collectively as the "Parties."

WHEREAS, Yampa Valley and Public Service are parties to an Amended and Restated Power Supply Agreement ("PPA") pursuant to which Yampa Valley purchases Full Requirements Service from Public Service as such term is defined in the PPA; and

WHEREAS, Yampa Valley is subject to the requirements of a Renewable Energy Standard adopted by the Colorado voters in 2004 in a ballot measure known as Amendment 37 and revised in HB10-1001, now codified at C.R.S. §40-2-124 (hereafter referred to, together with any associated regulations, as the "RES"), as the same may be changed by law from time to time; and

WHEREAS, Yampa Valley wishes to receive its Load Ratio Share (as defined below) of the Renewable Energy Credits (as defined below) acquired by Public Service from certain Renewable Energy Resources (as defined below) used by Public Service to meet its energy supply obligations under the PPA and agrees to pay the full costs associated with the acquisition of these renewable resources and associated RECs by Public Service;

NOW, THEREFORE, in consideration of the mutual covenants contained herein, the Parties do hereby agree as follows:

1. For purposes of this Agreement, the following terms shall be defined as:

a. "Designated Eligible Energy Resources" mean Eligible Energy Resources identified in Attachment 1 to this Agreement, as it may be amended from time to time.

b. "Designated Eligible Energy Resource Energy" means the energy in megawatt-hours produced in one calendar year from Designated Eligible Energy Resources.

c. "Eligible Energy Resources" means resources that generate Recycled Energy or Renewable Energy Resources, other than those resources that generate Specific Renewable Energy.

d. "Energy Sales to Yampa Valley under the PPA" means the total energy sales expressed in megawatt hours made by Public Service to Yampa Valley during the prior calendar year;

e. "Non-Distributed Generation or "Non-DG" means a renewable energy resource that is not Retail Renewable Distributed Generation or Wholesale Renewable Distributed Generation.

f. "Obligation Load Energy" shall have the meaning set forth in the Wholesale Fuel Cost and Economic Purchased Power Adjustment Clause ("FCA") of the PPA.

g. "Recycled Energy" means energy produced by a generation unit with a nameplate capacity of not more than fifteen megawatts that converts the otherwise lost energy from the heat from exhaust stacks or pipes to electricity and that does not combust additional fossil fuel. Recycled Energy does not include energy produced by any system that uses energy, lost or otherwise, from a process whose primary purpose is the generation of electricity, including, without limitation, any process involving engine-driven generation or pumped hydroelectricity generation. The resources must qualify for purposes of the RES.

h. "Renewable Energy Credit" or "Renewable Energy Certificate" or "REC" means those tradable renewable energy credits that may be used to comply with the RES, as contemplated by 40-2-124(1)(d).

i. "Renewable Energy Resources" means facilities that generate electricity by means of the following energy resources: solar radiation, wind, geothermal, biomass, fuel cells using hydrogen derived from Eligible Energy Resources. Hydropower resources in existence on January 1, 2005, must have a nameplate rating of thirty megawatts or less. Hydropower resources not in existence on January 1, 2005, must have a nameplate rating of ten megawatts or less. The resources must qualify for purposes of the RES.

j. "Retail Renewable Distributed Generation" or "Retail DG" means a renewable energy resource that is located on the premises of an end-use electric consumer located within the service territory of a Colorado retail electric service provider and is interconnected on the end-use electric consumer's side of the retail electric service provider's meter.

k. "Specific Renewable Energy" means energy generated from a specific Public Service owned or purchased resource that is directly assigned to a customer or customer class (*e.g.*, Yampa Valley Ponnequin Wind Energy).

l. "Wholesale Renewable Distributed Generation" or "Wholesale DG" means a renewable energy resource located in Colorado with a nameplate rating of 30 megawatts or less that does not qualify as Retail Renewable Distributed generation.

m. "WREGIS" means the Western Renewable Energy Generation Information System.

n. "Yampa Valley Load Ratio Share" or "Yampa Valley LRS" has the meaning given in paragraph #5 of this Agreement.

o. "Yampa Valley Ponnequin Wind Energy" means the energy Yampa Valley purchases from Public Service under the Power Purchase Agreement Between Yampa Valley and PSCo dated February 28, 1999 (PWEPPA) that is generated at the Ponnequin wind generation facility in northeast Colorado. To the extent the Yampa Valley PWEPPA terminates and is replaced by a successor PPA, this defmition shall include such successor PPA.

2. The Parties agree that Yampa Valley is entitled to the RECs associated with all Yampa Valley Ponnequin Wind Energy that is or was generated on and after January 1, 2004, through the term of the PWEPPA to the extent that Public Service is entitled to receive and does receive such RECs. Public Service shall transfer RECs associated with Yampa Valley Ponnequin Wind Energy generated on or after September 1, 2011, consistent with the process established in Paragraph 4 of this Agreement.

3. Yampa Valley is entitled to receive from Public Service pursuant to Paragraphs #4 and #5 of the Agreement, the Yampa Valley LRS of RECs associated with Designated Eligible Energy Resource Energy, but only to the extent such RECs are actually received by Public Service and such RECs are attributable to generation from Renewable Energy Resources.

4. Subject to the limitations specified in Paragraph #3 the Annual REC Transfer from Public Service to Yampa Valley for a year will be the Yampa Valley LRS entitlement applied to the RECs from Designated Eligible Energy Resources for a given year:

Beginning with the applicable RECs with a vintage on or after September 1, 2011, and continuing through the term of the PPA, the Yampa Valley LRS RECs will be transferred using the following process:

For each month in a given calendar year (the "Generation Year"), Public Service will transfer the Yampa Valley Load Ratio Share of the RECs associated with the generation data presented in the FCA Monthly True-up. RECs will be transferred monthly to Yampa Valley using WREGIS and will occur within one hundred (100) days past the end of the generation month ("Monthly REC Allocation"). The first REC transfer under this Agreement will occur within thirty (30) days after the approval of the settlement in Docket No. ER11-2853-000. Generation data for the first four months following the settlement date may be adjusted within the FCA Monthly True-ups to account for the process transition between the RECs transferred according to the prior Renewable Energy Credit Ownership Agreement and RECs transferred according to this Amended and Restated Renewable Energy Credit Ownership Agreement.

By May 1 of the year following the Generation Year, Public Service will make a final determination of RECs to be allocated to Yampa Valley based on the Annual REC Transfer calculation ("Final REC Allocation") which may result in the need for a true-up

of RECs for the year ("Annual REC True-Up"). Any Annual REC True-Up will be achieved as follows:

a. If the Final REC Allocation is higher than the sum of the Generation Year Monthly REC Allocations, Public Service will add the difference between the Final REC Allocation and the Generation Year Monthly REC Allocations from the first Monthly REC Allocation following the completion of the determination of the Final REC Allocation. As an example, if the 2012 Final REC Allocation exceeds the sum of the 2012 Monthly REC Allocations by 100 RECs, then Public Service will add 100 vintage 2013 RECs to the 2013 first Monthly REC Allocation following completion of the determination of the Final REC Allocation for Generation Year 2012.

b. If the Final REC Allocation is lower than the sum of the Generation Year Monthly REC Allocations, Public Service will subtract the difference between the Final REC Allocation and the Generation Year Monthly REC Allocations to the first Monthly REC Allocation following the completion of the determination of the Final REC Allocation. As an example, if the 2012 Final REC Allocation were less than the sum of the 2012 Monthly REC Allocations by 100 RECs, then Public Service will subtract 100 vintage 2013 RECs from the first Monthly REC Allocation following completion of the determination of the Final REC Allocation for Generation Year 2012.

Public Service and Yampa Valley will each establish and maintain status as an active WREGIS Account Holder to allow for the monthly transfers. Public Service must enter transfers so as to afford the standard 14 calendar day period for acceptance and Yampa Valley must confirm the proposed transfers in a timely manner under section 15.2 of the WREGIS Operating Rules. Should Yampa Valley fail to confirm and accept any RECs designated for monthly transfer to Yampa Valley prior to the expiration of the 14 calendar day window set out in WREGIS Operating Rule 15.2, Public Service will re-transfer equivalent RECs (in the same vintage year as the original transfer) as part of the subsequent Annual REC True-up. Public Service has no obligation to undertake such re-transfer at any time prior to the Annual REC True-up.

Public Service will transfer to Yampa Valley its Load Ratio Share (as defined in paragraph 5) of the RECs actually accrued in each combination of RES REC categories (Wholesale DG and Non-DG) and resource type (in-state wind, out-of-state wind, solar radiation, geothermal, biomass (including landfill gas), hydroelectric, hydrogen fuel cells and recycled energy) as presented in the table below. Public Service currently does not accrue RECs from all of these possible combinations. Public Service may transfer RECs from one or more generators that create RECs within each available combination.

RES REC Category	Resource Type
Wholesale DG	In-State Wind
Wholesale DG	Out-of-State Wind
Wholesale DG	Solar
Wholesale DG	Geothermal

Wholesale DG	Biomass/Landfill Gas
Wholesale DG	Hydro
Wholesale DG	Hydrogen Fuel Cells
Wholesale DG	Recycled Energy
Non- DG	In-State Wind
Non- DG	Out-of-State Wind
Non- DG	Solar
Non- DG	Geothermal
Non- DG	Biomass/Landfill Gas
Non- DG	Hydro
Non- DG	Hydrogen Fuel Cells
Non- DG	Recycled Energy

All labor costs incurred by Public Service to calculate the Monthly REC Allocations and to arrange the monthly transfer of the RECs in WREGIS to a customer, pursuant to an Amended and Restated Renewable Energy Credit Ownership Agreement, will be directly assigned on a pro rata basis to the customers responsible for such cost incurrence. Labor costs incurred by Public Service to calculate the Final REC Allocation will be assigned on a pro rata basis to all wholesale customers receiving RECs, based on each customer's share of the total RECs assigned in the year. Labor costs for the Annual REC True-up will be assigned to each wholesale customer based on its share of the RECs required to be transferred in the Annual REC True-up. Labor costs associated with Public Service's retirement of RECs for compliance or Public Service's sale of RECs to third parties shall be excluded from the costs assigned to customers receiving RECs.

If another process is developed in WREGIS that provides for a more efficient transfer of RECs or the WREGIS process is modified in a manner that is inconsistent with the process set out above, Public Service will notify Yampa Valley of the new process and the parties shall follow the process set out in Paragraph 11 of this Agreement.

Nothing in this Paragraph 4 limits Yampa Valley' entitlement to the Yampa Valley LRS of applicable RECs with a vintage prior to September 1, 2011.

5. The "Yampa Valley Load Ratio Share" or "Yampa Valley LRS" shall be defined and calculated as follows:

Yampa Valley LRS = (Energy Sales to Yampa Valley Under PPA – Yampa Valley Ponnequin Wind Energy) / (Obligation Load Energy –Specific Renewable Energy)

For purposes of calculating the Estimated REC Allocation the Yampa Valley LRS shall be determined using estimated values.

6. Yampa Valley and PSCo agree that the application of Appendix B-1, Renewable Energy Certificate Rider (Amended) ("REC Rider") to its PPA, which operating together with other elements of the PPA, provide for recovery of the Yampa Valley LRS of the total costs of

Designated Eligible Energy Resources from which Yampa Valley is entitled to receive RECs pursuant to this Agreement, including:

a. All costs associated with Designated Eligible Energy Resources that are uncollected by action of the economic screens used to calculate the FCA. The economic screens referred to here are the economic screens described in the Protocols For The Implementation of the Public Service Wholesale Fuel Cost And Economic Purchased Power Adjustment Clause ("FCA Protocols");

b. The costs of administering, registering, certifying, acquiring, and transferring RECs to Yampa Valley; and

c. All other costs associated with Designated Eligible Energy Resources that are not recovered by Public Service through base rates or the FCA.

Public Service shall provide Yampa Valley with detailed cost support for all such charges that Public Service passes through the REC Rider. Yampa Valley may question any such charges in the same time period as permitted for Yampa Valley' review of charges under the FCA. If such charges are not questioned within this time period, they shall be deemed final, and Yampa Valley shall not thereafter initiate any judicial or regulatory proceedings to contest such charges or the quantity and type of RECs transferred to Yampa Valley.

7. The provisions of this Agreement and the provisions of the PPA, including Appendix B-1, shall remain in effect following termination of the PPA to allow for the transfer by Public Service to Yampa Valley of all RECs to which Yampa Valley is entitled as a result of its purchases of energy under the PPA, including the true up of such transfers, and to allow Public Service to bill Yampa Valley its share of any uncollected costs (described in Paragraph 4 of Appendix B-1) for Designated Eligible Energy Resource Energy. Upon receipt of payment of Yampa Valley's share of total uncollected costs, Public Service will make a last and final transfer of RECs associated with Yampa Valley's prior calendar year purchases of Designated Eligible Energy Resource Energy and Yampa Valley's current calendar year purchases of Designated Eligible Energy Resource Energy. Alternatively, if Public Service determines in the final true-up that Yampa Valley should return RECs to Public Service, it shall notify Yampa Valley, and Yampa Valley shall do so within thirty (30) days of such notification.

8. Either Party may seek to terminate this Agreement if the FERC upon complaint or its own motion issues a final order modifying this Agreement and/or the REC Rider in a manner that such Party deems significant and adverse to it. The other Party retains all rights to oppose or challenge any such termination.

9. If Public Service is required or allowed by FERC to include for full cost recovery through base rates, the FCA, the REC Rider, or otherwise the cost of an Eligible Energy Resource which is of a type different from the resources specified in Attachment 1 to this Agreement, the Eligible Energy Resource will at that time become a Designated Eligible Energy Resource, and Yampa Valley will be entitled to the Yampa Valley LRS of the RECs associated with such Eligible Energy Resource. If Public Service includes only part of the costs of such Eligible Energy Resource in base rates or the FCA, Yampa Valley shall have the option to pay

through the REC Rider any additional costs of that Eligible Energy Resource not recovered through base rates or the FCA and receive its LRS of the RECs associated with the Eligible Energy Resource. In either such case, Attachment 1 will be revised to reflect the designation of such Eligible Energy Resource as a Designated Eligible Energy Resource. This Paragraph shall not be interpreted as requiring that Public Service include in its base rates or through the FCA any resources not identified in Attachment 1 to this Agreement.

10. Public Service will maintain records sufficient to identify by month the quantity of Designated Eligible Energy Resources and RECs from the Designated Eligible Energy Resource Energy that are subject to the terms of this Agreement. Public Service will take such actions as are necessary and/or are reasonably requested by Yampa Valley in order to certify as RES compliant and transfer title to all RECs to which Yampa Valley is entitled under this Agreement and to establish to third parties, including the Colorado Public Utilities Commission ("CPUC"), that clear title to the RECs was transferred. Public Service has no obligation to acquire certification for RECs except in the event that the CPUC should impose such requirement for RES compliance. Any WREGIS costs incurred by Public Service on behalf of Yampa Valley will be included in costs recovered by the REC Rider.

11. In the event that the RES, which is in effect as of the date of this Agreement, is subsequently amended by the Colorado General Assembly or by the voters of Colorado, or another REC Tracking System is developed that can be used for RES compliance, the Parties shall make such changes to this Agreement as are appropriate such that the benefits of the Agreement to both Parties are preserved. If either Party wishes to make such changes, it shall notify the other Party, and the Parties shall negotiate in good faith such modifications as they deem necessary. If the Parties are unable to negotiate mutually agreeable modifications to the Agreement within one hundred and twenty (120) days after the date one party receives notice from the other Party requesting modifications, then either Party may exercise its rights under the Federal Power Act to have this Agreement and the REC Rider modified.

IN WITNESS WHEREOF, on the date set forth above, the Parties hereto have caused this Agreement to be executed in their respective names by their authorized representatives.

PUBLIC SERVICE COMPANY OF COLORADO,
a Colorado corporation

By: _____
Name: David L. Eves
Title: President and CEO
Public Service Company of Colorado

YAMPA VALLEY ELECTRIC ASSOCIATION, INC.,
a Colorado cooperative electric association

By: Lawrence D Covillo
Name: Lawrence D. Covillo
Title: President and General Manager

ATTACHMENT 1 TO APPENDIX B-2:
DESIGNATED ELIGIBLE ENERGY RESOURCES:

- All Wind
- All Geothermal
- All Biomass
- All New hydroelectricity with a nameplate rating of ten megawatts or less
- All Hydroelectricity in existence on January 1, 2005, with a nameplate rating of thirty megawatts or less
- All Recycled Energy
- All Wholesale DG and Non-DG solar

Excluded resources: All Retail DG

Colorado PUC E-Filings System

PUBLIC SERVICE COMPANY OF COLORADO
RESPONSE TO CITY OF BOULDER REQUEST FOR PROPOSALS
May 18, 2015

Public Service Company of Colorado (Public Service) hereby submits this Response to the Request for Proposals (RFP) released by the City of Boulder, Colorado (Boulder), on April 16, 2015.

I. Executive Summary

Boulder's RFP solicits proposals for a requirements contract with a minimum term of five years. The RFP is directed primarily at Public Service. The RFP includes summary level information regarding the nature of the service sought and indicates that Boulder is pursuing multiple competing objectives. For example, it requests a proposal for 100 percent of Boulder's electric requirements, but also requests proposals to enable that Boulder reduce its wholesale purchases from Public Service over time (perhaps to be replaced with renewable energy resources). The RFP also states that one of Boulder's objectives is to mitigate stranded cost liability.

In an effort to assist Boulder in considering its options, Public Service hereby responds with a conceptual framework of a requirements arrangement that could help to satisfy Boulder's primary objectives while at the same time protecting Public Service's other customers against generation-related cost shifts. This conceptual framework is also consistent with the Federal Energy Regulatory Commission's (FERC) order rejecting, without prejudice, Boulder's Petition for Declaratory Order with respect to the effect of a partial requirements agreement on Boulder's stranded cost liability.

In summary, Public Service's conceptual framework includes the following primary components:

- Public Service will file with FERC to recover the stranded costs associated with Boulder's planned municipalization. Public Service's filing will, among other things, specify the Length of Obligation (L Period) and the market value of the capacity and energy released by Boulder's departure. Given the potential difficulty of reaching mutual agreement on stranded cost recovery, Public Service believes that filing at FERC can provide greater certainty to Boulder by enhancing its ability to structure a requirements agreement to provide for stranded cost mitigation.

- Consistent with the assumptions set forth in the stranded cost filing (e.g., the L Period), Public Service would be willing to provide wholesale requirements service to Boulder. For example, Boulder could purchase full requirements service from Public Service for five years and thereafter shift its requirements purchases to another supplier and pay Public Service's FERC-approved stranded cost charge for the remaining years of the L Period. Public Service would also be willing to discuss a partial requirements agreement under which Boulder would purchase an identified amount of power from third parties and/or self-generate and, with respect to the

amount of load shifted to such other sources, pay a stranded cost "make whole payment."

- Boulder will also need to arrange for transmission and applicable ancillary services pursuant to Public Service's Open Access Transmission Tariff (OATT) no matter whether Boulder purchases requirements service from Public Service or from an alternative supplier. Boulder will also need to meet the reciprocity obligations set forth in the OATT with respect to any service required by Public Service to serve its other customers.

Public Service offers this conceptual framework in a good faith effort to provide Boulder information regarding its power supply options and associated stranded cost mitigation. This conceptual framework is, however, without prejudice to all pending and potential future litigation relating to municipalization. Public Service continues to believe that a municipalization is not in the best interests of Boulder customers or Public Service's other customers.

Public Service is providing this response on a non-confidential basis. If Boulder wishes to discuss a possible arrangement with Public Service, we can discuss at that time whether discussions should be confidential or not.

II. Overview of the City of Boulder RFP

The RFP seeks power supply proposals from Public Service and other interested bidders according to certain stated assumptions, not all of which are clearly or consistently defined. The statements in the RFP regarding certain key assumptions are summarized below:

- *Term.* The term of the requested requirements contract is a "minimum" of five years, commencing on January 1, 2018. There is no reference to a maximum term, a right of extension, or a right of early termination.

- *Quantity.* Boulder states that it desires to purchase a "fixed percent of the Public Service generation and capabilities" (page 4), but also indicates that Boulder desires to purchase "100 percent" of its requirements for the contract term, with the only exclusions being energy supplied from behind-the-meter generation (page 5). However, Boulder also indicates that it wishes to "gradually introduce" purchases from other suppliers over the contract term (page 5).

- *Resource Types.* Boulder desires to purchase a "fixed percent of the Public Service generation and capabilities" on a "Slice of System" basis (page 4), but also states that it may desire to procure a higher percentage of its requirements from renewable sources than would be represented in a slice of system purchase from Public Service (page 7).

- *Rates.* Boulder states that it desires to pay a "fixed percent of Public Service's power costs" (page 4). Boulder indicates that the pricing should be "fixed" for both the capacity and energy charge (page 7). Boulder also states, however, that it is open to

considering different forms of "pricing for various contract structures," including "market based price[s]" (page 7).

- *NonRate Terms and Conditions.* The RFP attaches a standard form of Master Power Purchase and Sale Agreement often used for shorter-term purchases and sales at market-based prices.

- *Stranded Cost Recovery.* Boulder states that the requirements contract should "limit the City's exposure to stranded costs" (page 7).

- *Transmission and Ancillary Services.* The RFP states that any response should include an offer to procure the associated transmission and ancillary services on behalf of Boulder (pages 4-5).

III. Requirements Service and Stranded Cost Mitigation

The following is a general description of a conceptual framework that could facilitate a requirements arrangement between Public Service and Boulder under which Boulder receives credits against its stranded cost obligations for requirements purchases from Public Service. Public Service anticipates submitting a stranded cost filing at FERC in the near future and, consistent with the assumptions set forth in that filing, Public Service would be willing to discuss various crediting mechanisms that provide stranded cost mitigation for requirements purchases from Public Service. Section VII below provides further information on stranded cost recovery.

A. Term and Stranded Cost Mitigation

The most straightforward approach for Boulder to achieve full stranded cost mitigation is to execute a full requirements agreement with Public Service for a term that coincides with the L Period. For example, assuming the L Period is 20 years and deemed to begin in 2017, Boulder would need to continue purchasing full requirements service until 2037 to fully mitigate stranded costs.

Public Service recognizes, however, that Boulder may desire a contract that is both shorter than the L Period and also potentially allows purchases from third parties and/or self-generation options. Public Service would be willing discuss such options and develop a means for reconciling those options against the FERC-approved stranded cost charge. The simplest way to reconcile a requirements contract with full stranded cost recovery would be for Boulder to purchase its full requirements from Public Service for a defined period of years (e.g., five years) and then switch its entire load to another supplier(s) after that time and pay a full stranded cost charge for the remaining years in the L Period. Because Boulder has expressed some interest in a partial requirements arrangement, however, Public Service also discusses below how such an arrangement could be reconciled with full stranded cost recovery in the next section.

B. Partial Requirements Options and Stranded Cost Mitigation

The most straightforward approach to crediting a partial requirements purchase against stranded cost liability is for Boulder to procure a fixed slice of its load shape from an alternative supplier(s). For example, if Boulder entered into a partial requirements contract under which

Public Service supplied 90% of its load in every hour, Boulder would receive a 90% credit against the FERC-approved stranded cost charge during each year in which the partial requirements contract was in effect. In addition, as noted above, Boulder would also pay a full stranded cost charge for any remaining years on the L Period after it ceases requirements purchases from Public Service.

Public Service is also willing to discuss other arrangements in which Boulder does not procure a fixed slice of its load shape from alternative suppliers. For example, Boulder may desire to make discrete purchases from wind resources or add solar generation behind the meter. Supply arrangements of this type would introduce complexity in developing a stranded cost crediting mechanism, particularly for variable resources. However, Public Service is willing to discuss this issue. Accordingly, if Boulder can provide more information on the nature of the alternative supplies it is likely to acquire, Public Service can develop and tailor an appropriate stranded cost crediting mechanism at that time.

C. Rates

Boulder states that it is willing to consider a range of rate structures for a requirements contract, but in several places indicates that it prefers "fixed" rates. Public Service already has FERC-approved tariff rates for wholesale requirements service. *See Public Serv. Co. of Colorado*, 135 FERC 61,012 (2011). Pursuant to the Assured Power and Energy Requirements Service Tariff, Public Service recovers its costs from wholesale requirements customers using a formula rate that has a forward-looking test year that is later trued up against actual costs and demands. Public Service currently serves six wholesale requirements customers under the Assured Power and Energy Requirements Service Tariff. Public Service anticipates that any requirements agreement with Boulder would utilize the formula rates set forth in that Tariff.

D. Non-Rate Terms and Conditions

Boulder has proposed a modified form of the Edison Electric Institute Master Power Purchase and Sales Agreement (the EEI) to govern certain non-rate terms and conditions. Public Service presently provides wholesale requirements services to six customers pursuant to its Assured Power and Energy Requirements Service Tariff. This tariff serves as an umbrella agreement for the individually negotiated requirements contracts with each customer. Although the EEI Master Agreement was developed primarily with shorter-term transactions in mind, Public Service would be willing to consider using the EEI template to develop an individual requirements service arrangement with Boulder once certain key issues (e.g., term, quantity and stranded cost mitigation) have been resolved. Boulder may find it preferable, however, to develop a contract more similar to those of Public Service's other customers.

IV. Transmission Service

The RFP indicates that Boulder intends to take network integration transmission service. Public Service's OATT provides the rates, terms and conditions for network integration transmission service, as well as the procedures for applying for that service. Although Public Service has arranged for transmission services to serve some (but not all) of Public Service's other wholesale requirements customers, Boulder's planned acquisition of facilities from Public

Service, as we presently understand it, raises certain unique issues, including how Boulder intends to comply with the reciprocity provisions of the OATT. It would also be difficult for Public Service to make transmission arrangements without knowing what additional generation resources Boulder is contemplating. Accordingly, Public Service suggests that, when Boulder has a better understanding of the nature of the service it wants, Boulder submit a request for transmission service under Public Service's OATT in support of any power supply arrangement. Public Service will process that application pursuant to the terms and conditions of the OATT. As part of this process, Boulder will also need to meet its reciprocity obligations under Section 6 of the OATT with respect to any service required by Public Service to serve its other customers.

V. Ancillary Services

The ancillary services that Boulder will need to acquire are specified in Public Service's OATT, and will need to be requested in accordance with the procedures specified in that tariff.

VI. RFP Bidder Requirements

The RFP contains several specific requirements for a conforming power supply bid. Because Public Service is submitting only a conceptual framework, not a formal bid, this additional information is not included.

VII. Stranded Cost Recovery

On April 29, 2011, Boulder requested that Public Service provide an estimate of Boulder's stranded cost liability if it effectuated a municipalization and thereby became a retail-turned-wholesale customer. On June 3, 2011, Public Service responded with a good faith, nonbinding estimate of Boulder's stranded cost liability that, among other things, used a 20-year L Period for calculating stranded costs.

On May 17, 2013, without previously discussing a partial requirements arrangement with Public Service, Boulder filed a Petition for Declaratory Order with the FERC requesting a finding that "Boulder will have no stranded cost obligation for the portion of its wholesale power requirements that Boulder purchases from its former retail supplier, Public Service Company of Colorado (Public Service)." *City of Boulder, Colorado*, 144 FERC ¶ 61,069 at P 1 (2013) (*Order Denying Boulder Petition*). Boulder stated that obtaining certainty on this issue would "greatly enhance Boulder's ability to estimate accurately and manage its potential exposure to stranded costs." Boulder Petition at 4.

On July 29, 2013, FERC denied the Petition without prejudice, noting that Boulder had not yet requested a partial requirements contract from Public Service and, consequently, "the Commission has no facts regarding Boulder's proposed municipalization, such as the length of a prospective partial requirements contract with Public Service and the length of the period for which Public Service had a reasonable expectation of continued service to Boulder." *Id.* at P 32. Similarly, the FERC stated that "the extent of Boulder's stranded cost obligation would be a fact-specific determination that could only be made when the terms of a future partial requirements contract with Public Service are known." *Id.* at P 33.

In 2014, Boulder approached Public Service to discuss the potential terms of a partial requirements contract. After an initial meeting on September 4, 2014 between representatives from Boulder and Public Service, Boulder expressed an interest in Public Service making a specific power supply offer. On November 26, 2014, Public Service responded and explained that, to be fair to Public Service's non-Boulder customers, Public Service would be willing to discuss a power supply arrangement, but only in conjunction with a discussion of stranded cost recovery. On December 9, 2014, Boulder replied that it did not wish to discuss the specifics of stranded cost recovery at this time.

Boulder is now seeking a requirements contract that, among other things, "limit[s] the City's exposure to stranded costs and avoid[s] impact to other rate payers in PSCo's service territory." (page 7). Public Service agrees with this general objective, which is also firmly embedded in FERC's landmark Order No. 888, where FERC found that "it is appropriate that the departing generation customer, and not the remaining generation or transmission customers (or shareholders), bear its fair share of the legitimate and prudent obligations that the utility undertook on that customer's behalf." Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,797 (1996) (emphasis added). "[I]f the Commission fails to give a public utility the opportunity to directly assign costs to the customers on whose behalf they were incurred . . . , third parties (the utility's remaining customers) will be harmed by having to bear the costs that were not incurred to serve them and that are stranded by other customers' departures via open access transmission." *Id*. at 31,812 (emphasis added).

Public Service wishes to emphasize, however, that FERC's stranded cost recovery formula is designed to compensate the utility for generation investments made *prior* to the date of the customer's departure, not generation investments made *after* that departure. Consequently, we wish to stress that Boulder's desire to reduce its purchases from Public Service to avoid the incurrence of *future* resource acquisitions by Public Service is not relevant to stranded cost mitigation. RFP at 5, 7. FERC has held that a retail-turned-wholesale customer's responsibility for past generation investments cannot be mitigated through the future load growth of other, non-departing customers. *City of Las Cruces*, 87 FERC ¶ 61,201, at 61,750 (1999); *City of Alma*, 96 FERC ¶ 61,163, at 61,715 (2001). Even if the customer's departure allows the utility to avoid making new generation investments, the customer's stranded cost liability remains unaffected *unless* the relevant state commission specifically approves as reasonable the resulting cost shifts to other customers. *See Las Cruces*, 87 FERC at 61,760-61; *City of Alma*, 96 FERC at 61,721.

VIII. Contact Information

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