

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * *

IN THE MATTER OF THE APPLICATION)
OF PUBLIC SERVICE COMPANY OF)
COLORADO FOR APPROVAL OF ITS) PROCEEDING NO. 21A-____E
2021 ELECTRIC RESOURCE PLAN AND)
CLEAN ENERGY PLAN)
)

DIRECT TESTIMONY OF JAMES F. HILL

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

March 31, 2021

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

<u>Acronym/Defined Term</u>	<u>Meaning</u>
2021 ERP & CEP	2021 Electric Resource Plan and Clean Energy Plan
CC	Combined Cycle
CEP	Clean Energy Plan
CO ₂	Carbon Dioxide
CPCN	Certificate of Public Convenience and Necessity
CPUC	Colorado Public Utilities Commission
DG	Distributed Generation
DSM	Demand Side Management
ERP	Electric Resource Plan
IPP	Independent Power Producer
kW	Kilowatt
kWh	Kilowatt-hour
L&R	Load and Resource
LOLP	Loss of Load Probability
MWh	Megawatt hour
PPA	Power Purchase Agreement
Public Service or Company	Public Service Company of Colorado
PV	Photovoltaic
PVRR	Present Value Revenue Requirement
RAP	Resource Acquisition Period

RECs	Renewable Energy Credits
RE Plan	Renewable Energy Plan
RES	Renewable Energy Standard
RESA	Renewable Energy Standard Adjustment
Retail DG	Retail Distributed Generation
RFP	Request for Proposal
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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1 **I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

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

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

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

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

12 A. I am testifying on behalf of Public Service.

1 **Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.**

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

8 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

9 A. The purpose of my Direct Testimony is to support the Company's 2021 Electric
10 Resource Plan and Clean Energy Plan ("2021 ERP & CEP") from a resource
11 planning perspective. I provide an overview of the Electric Resource Plan
12 ("ERP") process in general, and then I discuss how the Company developed and
13 modeled various portfolios and coal actions. I provide the results of the
14 Company's Phase I portfolio analysis and discuss the Company's selection of its
15 preferred plan.

16 **Q. BEFORE DESCRIBING THE ORGANIZATION OF YOUR TESTIMONY, CAN**
17 **YOU SUMMARIZE THE COMPANY'S PREFERRED CEP?**

18 A. Yes. For the reasons I discuss in my Direct Testimony, the Company's preferred
19 Clean Energy Plan ("CEP") is portfolio "SCC 7". The preferred plan portfolio is
20 one that has been optimized using the social cost of carbon ("SCC") rather than
21 \$0/ton for carbon. Specifically, the coal actions of the preferred plan (SCC 7)
22 include:

- 1 1. Early retirement of Craig 2 in 2028 and Hayden 1 in 2028 and Hayden 2 in
2 2027;
- 3 2. Conversion of Pawnee to burn natural gas by 2028; and
- 4 3. Reducing generation from Comanche 3 to a level representative of a 33
5 percent annual capacity factor beginning in 2030 and early retiring the unit
6 in 2040.

7 Coupled with these coal actions, the preferred plan includes indicative
8 levels of generic wind, solar, storage, and firm and flexible dispatchable
9 resources of approximately 2,300 megawatts (“MW”), 1,600 MW, 400 MW, and
10 1,300 MW, respectively. The actual level and composition of these and other
11 resource technologies in the preferred plan will be determined through the Phase
12 II competitive solicitation and bid evaluation process.

13 **Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?**

14 A. In Section II, I set the stage by providing an overview of the ERP process,
15 including a description of the two phases of an ERP proceeding: Phase I and
16 Phase II. I also describe two key factors that materially influenced the
17 preparation of this Phase I 2021 ERP & CEP, including: (1) the requirement that
18 our generation portfolio(s) must achieve specific clean energy targets as a result
19 of the passage of Senate Bill 19-236 (“SB 19-236”); and (2) the requirement of
20 SB 19-236 to use the social cost of carbon in the optimization of resource
21 planning portfolios in our modeling.

22 In Section III, I discuss the resource acquisition period (“RAP”) and
23 planning period used for this 2021 ERP & CEP. SB 19-236 requires that the
24 Company use a RAP through 2030 to align with the clean energy target of 80

1 percent emission reduction by 2030 from 2005 levels. The Company proposes a
2 planning period from 2021 through 2055.

3 In Section IV, I explain how the Company conducted its assessment of the
4 need for additional generation resources over the RAP. Specifically, I discuss
5 the five key areas that factor into the assessment of resource need, including: (1)
6 generation capacity needs; (2) generation needed to reduce emissions; (3) the
7 need for flexible generation resources; (4) dispatchable resource needs for
8 system reliability; and (5) the need for additional resources to comply with the
9 Renewable Energy Standard (“RES”).

10 In Section V, I explain how we developed the “ERP portfolios” and the
11 “CEP portfolios” for purposes of this Phase I filing. Specifically, I explain that the
12 ERP portfolios were developed to meet the base resource need, (i.e., the needs
13 reflected in our load forecast inclusive of the previously announced accelerated
14 retirements of Craig 2, Hayden 1, and Hayden 2), and how they are not required
15 within the modeling to meet the clean energy target in 2030. In contrast, I
16 explain that the CEP portfolios reflect additional coal transitions at Pawnee and
17 Comanche 3 and additional resource acquisitions that are required to meet the
18 80 percent clean energy target established by SB 19-236. Next, I step through
19 the framework used for the analysis of the ERP and CEP portfolios and explain
20 the various coal actions and combinations of actions considered in the analysis.

21 In Section VI, I explain the results of the ERP and CEP portfolio
22 optimizations using the SCC. Specifically, I describe the generic resources that
23 were optimized, the estimated potential infrastructure investment, the incremental

1 costs/benefits, the projected rate impact, and the carbon reduction efficiency
2 associated with each of the ERP and CEP SCC portfolios.

3 In Section VII, I explain the results of the ERP and CEP portfolio
4 optimizations using an assumption that the cost for each ton of carbon emitted
5 has a \$0/ton cost. I describe the results using the same framework as laid out in
6 Section VI.

7 In Section VIII, I discuss the Company's conclusions from the ERP and
8 CEP portfolio analysis and explain the various factors that influenced the
9 Company's selection of SCC 7 as its preferred plan.

10 In Section IX, I discuss the various sensitivities performed by the
11 Company to further analyze the ERP and CEP portfolios. These sensitivity
12 analyses involve changing a single key input assumption and assessing how that
13 change impacts a portfolio's carbon cost (i.e., repricing sensitivity) or the
14 composition of resources added within the portfolio (i.e., reoptimized sensitivity).
15 The primary purpose of sensitivity analyses is to test the robustness of the
16 Company's selection of SCC 7 as our preferred plan under different futures. I
17 discuss a few of the more informative sensitivity analysis results and note that a
18 more detailed discussion is provided in Volume 2 of the Company's ERP.¹

19 In Section XI, I explain that, consistent with the requirements of SB 19-236
20 and past practice, the Company is proposing to utilize an All-Source competitive
21 solicitation process in Phase II to acquire the resources necessary to meet the

¹ Volume 2 is included as Attachment AKJ-2 to the Direct Testimony of Company witness Ms. Alice K. Jackson.

1 various needs and objectives of this 2021 ERP. I note that the use of competitive
2 procurement is the foundation of the successful ERP paradigm in Colorado. I
3 also summarize specific reliability requirements that the Company proposes be
4 employed in the evaluation and selection of Phase II bids.

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

7 A. No.

8

1 **II. OVERVIEW OF PUBLIC SERVICE’S RESOURCE PLANNING PROCESS**

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

4 A. In this section of my Direct Testimony, I provide an overview of the ERP process,
5 the objectives of the Company’s 2021 ERP & CEP, and a discussion of how the
6 2021 ERP & CEP compares to the Company’s last 2016 ERP.

7 **Q. DOES THE COMMISSION REQUIRE PUBLIC SERVICE TO DEVELOP AND**
8 **FILE AN ERP?**

9 A. Yes. The Commission has established rules requiring electric utilities to develop
10 and file ERPs generally on a four-year cycle. The Commission’s rules specify
11 what must be contained in electric utilities’ ERPs and the process electric utilities
12 must undertake to implement their ERPs. The Colorado ERP process is looked
13 to nationally as a model for the acquisition of cost effective and increasingly
14 clean generation resources. As I will describe in this section of my Direct
15 Testimony, the Company intends to utilize this process to advance the State of
16 Colorado toward its emission reduction goals—as contemplated by the General
17 Assembly with the passage of SB 19-236.

18 **Q. WHAT IS THE GENERAL OBJECTIVE OF AN ERP?**

19 A. As specified by the Commission’s rules, the ERP process focuses on identifying
20 additional generation resources or changes to existing generation resources that

1 are needed to meet certain future objectives in a cost effective and reliable
2 manner.² An ERP consists of two phases: Phase I and Phase II.

3 **Q. PLEASE DESCRIBE PHASE I OF THE ERP PROCESS.**

4 A. Phase I identifies generation resource needs (including quantities and generation
5 resource types) that will meet specified objectives. Examples of objectives in an
6 ERP include acquiring new generation to meet growing customer demand for
7 power (i.e., the amount not served by Demand Side Management (“DSM”) or
8 Distributed Energy Resources (“DERs”)), new resources to meet RES
9 requirements, new resources to take advantage of Federal tax credits to help
10 reduce costs to customers, and new resource additions or retirements to meet
11 environmental objectives such as emission reduction or clean energy targets.

12 **Q. PLEASE DESCRIBE PHASE II OF THE ERP PROCESS.**

13 A. In Phase II, the Company implements a competitive acquisition process for new
14 resources. Public Service evaluates and develops portfolios of bids that meet
15 the Commission’s Phase I directives (overseen by an independent evaluator) for
16 Commission consideration. Through a Phase II decision, the Commission
17 ultimately selects specific resources to satisfy the resource needs. The
18 Company then pursues the acquisitions of those generation resources through
19 follow-on Certificate of Public Convenience and Necessity (“CPCN”) proceedings
20 and Power Purchase Agreement (“PPA”) negotiations. I would also note that for
21 this ERP, where specific legislation (i.e., SB 19-236) directs the inclusion of a
22 Clean Energy Plan, Phase I will also evaluate potential actions with the

² See 4 CCR 723-3-3600, *et seq.*

1 Company's remaining coal fleet. Through this Phase I process, the Company is
2 seeking—along with approval of modeling inputs, assumptions, methodologies,
3 and its 2021 ERP & CEP—approval of a specific set of actions to the existing
4 coal fleet to ensure the right resource need is filled in the Phase II competitive
5 solicitation.

6 **Q. IS THE 2021 ERP & CEP DIFFERENT IN ANY REGARD IN COMPARISON TO**
7 **THE 2016 ERP THAT RESULTED IN THE COLORADO ENERGY PLAN?**

8 A. Yes. The 2021 ERP & CEP is the first ERP cycle with specific clean energy
9 targets that our generation portfolio(s) must meet as a result of the passage of
10 SB 19-236. Specifically, the Company is required to file a plan that achieves an
11 80 percent carbon dioxide emission reduction from 2005 levels by 2030, which
12 equates to a plan that emits approximately 5.4 million short tons (“MST”) of
13 carbon dioxide emissions in 2030. This emission constraint changes the ERP
14 process in some ways because it is the first time we have done resource
15 planning and modeling for Public Service Company with a specific emission cap
16 in place. This planning process is also different because we are using the social
17 cost of carbon in the optimization of resource planning portfolios in our
18 EnCompass modeling.³ This value has been used as a sensitivity in previous
19 ERPs, but in this plan we are including it in the optimization of portfolios as
20 directed by SB 19-236. The modeling of portfolios to meet statutory clean energy
21 targets and use of the SCC in the modeling are two foundational changes from

³ Please refer to the Direct Testimony of Mr. Jon T. Landrum for a discussion of the Company's modeling process and assumptions.

1 SB 19-236 that materially influenced the preparation of this Phase I 2021 ERP &

2 CEP.

3

1 **III. RESOURCE ACQUISITION PERIOD AND PLANNING PERIOD**

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

4 A. In this section of my Direct Testimony, I discuss the RAP and planning period
5 that the Company proposes to use for this 2021 ERP & CEP.

6 **Q. WHAT IS THE SIGNIFICANCE OF THE RESOURCE ACQUISITION PERIOD**
7 **OR “RAP”?**

8 A. The RAP is the period of time over which the utility acquires specific generation
9 resources to meet projected resource needs. Typically, the Commission’s ERP
10 rules allow jurisdictional utilities to select a RAP between six and ten years from
11 the date the plan is filed.

12 **Q. DOES SB 19-236 ESTABLISH THE RAP TO BE USED WHEN A UTILITY’S**
13 **ERP CONTAINS A CEP?**

14 A. Yes. SB 19-236 requires the ERP containing the CEP to utilize a RAP that
15 extends through 2030. Since the 2021 ERP contains the Company’s CEP, the
16 Company will utilize a RAP for the 2021 ERP & CEP that covers years 2021
17 through 2030. This RAP will be applied to both ERP portfolios and CEP
18 portfolios. I address the difference between “ERP portfolios” and “CEP
19 portfolios” in more detail later in my Direct Testimony.

20 **Q. WHAT IS THE SIGNIFICANCE OF THE PLANNING PERIOD?**

21 A. The "planning period" represents the future period for which a utility develops its
22 plan, and the period over which the costs and benefits of new resources are
23 evaluated by the utility. The planning period also defines the time over which net

1 present value of revenue requirements and emission costs for resources are
2 calculated.

3 In establishing the proposed planning period, the Company sought to
4 comply with existing ERP rules but also take guidance from discussions around
5 the planning period in the not finalized rulemaking proceeding in Proceeding No.
6 19R-0096E. Based on this approach, we analyzed a “planning period” of 20 to
7 40 years and beginning no later than January 1 following the date the utility files
8 its plan with the Commission. The planning periods considered by the Company
9 extended either through the 20-year period following the last year of the RAP or
10 extended beyond the RAP for a period equal to the longest proposed contract
11 term length.

12 **Q. WHAT CONTRACT TERM LENGTH IS THE COMPANY PROPOSING IN ITS**
13 **PHASE II REQUEST FOR PROPOSALS?**

14 A. We are proposing contract term lengths up to 25 years.⁴

15 **Q. WHAT PLANNING PERIOD IS THE COMPANY RECOMMENDING?**

16 A. Public Service proposes a planning period from the plan filing year of 2021
17 extending through 2055, or approximately 35 years, which represents the period
18 following the last year of the RAP (i.e., 2030) through the last year of the
19 proposed 25-year contract term length in the model contracts filed in Volume 3 of
20 our ERP.

⁴ The contract term lengths are based in part on avoiding or minimizing adverse financial impacts of imputed debt, finance lease, and variable interest entity-related obligations.

1 **IV. ASSESSMENT OF RESOURCE NEED: ERP AND CLEAN ENERGY PLAN**

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

4 A. In this section of my Direct Testimony, I explain how the Company conducts its
5 assessment of the need for additional generation resources over the RAP.
6 Specifically, I discuss the five key areas that factor into the assessment of
7 resource need, including: (1) generation capacity needs; (2) generation needed
8 to reduce emissions; (3) the need for flexible generation resources; (4)
9 dispatchable resource needs for system reliability; and (5) the need for additional
10 resources to comply with the RES.

11 **Q. DOES SB 19-236 OUTLINE SPECIFIC REQUIREMENTS REGARDING THE**
12 **COMPANY'S ASSESSMENT OF RESOURCE NEED?**

13 A. Yes. SB 19-236 requires the Company to clearly distinguish between: (1) the
14 resources necessary to meet customer demands in the RAP; and (2) the
15 additional resource need created by actions taken to meet the 80 percent clean
16 energy target (e.g., retirement of existing generating facilities, changes in system
17 operations, etc.).

18 **Q. HOW DOES THE COMPANY DISTINGUISH BETWEEN THESE TWO**
19 **CATEGORIES OF RESOURCE NEED IN ITS PHASE I ANALYSIS?**

20 A. As I will discuss in more detail in Section V of my Direct Testimony, the
21 Company developed "ERP portfolios" and "CEP portfolios" to clearly distinguish
22 between these two resource needs, as required by SB 19-236. The ERP
23 portfolios meet what I refer to as the base need, i.e., the needs reflected in our

1 load and resource balance inclusive of the previously announced retirements of
2 Craig 2, Hayden 1, and Hayden 2. ERP portfolios are not required within the
3 modeling to meet the 80 percent emission reduction target in 2030. In contrast,
4 CEP portfolios reflect additional coal actions at Pawnee and Comanche 3 and
5 the additional resource acquisitions required to meet the 80 percent emission
6 reduction target in 2030, as established by SB 19-236.

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

9 A. The assessment of need is focused on five areas:

- 10 1. Generation capacity needs for system reliability;
- 11 2. Generation needed to reduce emissions;
- 12 3. Flexible resource needs for integrating intermittent resources;
- 13 4. Dispatchable resource needs for system reliability; and
- 14 5. Resources needed to comply with the RES.

15 The results of these assessments identified: (1) no need in years 2021
16 through 2025 for additional generation capacity to maintain acceptable system
17 reliability, and increasing needs for each year from 2026 to 2030; (2) no need for
18 additional renewable resources for the purpose of meeting the "minimum
19 amounts" reflected in the percentage requirements of the RES;⁵ (3) the Flex
20 Reserve Study work identifies the volume of flexible resources needed to
21 accommodate up to three gigawatts ("GW") of incremental wind generation; and

1 (4) a need for additional emission reduction efforts to meet the statutory clean
2 energy target of SB 19-236.

3 **A. Generation Capacity Needs**

4 **Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL**
5 **GENERATION CAPACITY IS NEEDED FOR SYSTEM RELIABILITY**
6 **PURPOSES?**

7 A. We forecast whether sufficient planning reserve margin would be maintained
8 throughout each summer peak season during the RAP to make this
9 determination. The peak electric demand forecast discussed in the Direct
10 Testimony of Company witness Mr. John M. Goodenough is compared with the
11 existing and planned generation resources. This is commonly referred to as the
12 load and resource balance or, load and resource table (“L&R”).

13 **Q. PLEASE EXPLAIN THE PLANNING RESERVE MARGIN.**

14 A. Planning reserve margin is the amount of generation capability in excess of peak
15 firm obligation load that a utility carries on its system in order to meet customer
16 demand under system uncertainties. The Company proposes utilizing an 18
17 percent planning reserve margin for purposes of acquiring resources in Phase II
18 of this 2021 ERP.

19 **Q. WHAT IS THE BASIS FOR AN 18 PERCENT PLANNING RESERVE MARGIN?**

20 A. The 18 percent planning reserve margin is the result of a updated planning
21 reserve margin study that was performed by Astrapé Consulting for Public

⁵ No additional wholesale DG or non-DG resources are needed to comply with the RES through 2030 and beyond. The need for additional retail-DG resources are determined in the Company’s Renewable

1 Service in accordance with Commission directives from the 2016 ERP in
2 Proceeding No. 16A-0396E.⁶ The updated planning reserve margin study is
3 discussed in detail in the Direct Testimony of Company witness Mr. Kevin D.
4 Carden of Astrapé Consulting and is provided as Attachment KDC-1 to Mr.
5 Carden's Direct Testimony.

6 **Q. HOW ARE THE EFFECTS OF THE COMPANY'S DEMAND SIDE**
7 **MANAGEMENT PROGRAMS ACCOUNTED FOR IN THE LOAD AND**
8 **RESOURCE BALANCE?**

9 A. Consistent with prior ERPs, the forecast of summer peak load is reduced by the
10 combined effects of the Company's DSM programs,⁷ based on goals approved
11 by the Commission in other proceedings. Company witness Mr. Jack W. Ihle
12 addresses the interactions of the ERP with other planning processes (i.e., DERs,
13 DSM, etc.). After accounting for DSM programs, the resulting load is referred to
14 as firm obligation load. The 18 percent planning reserve margin is applied to the
15 forecast of firm obligation load for each year of the RAP.

16 **Q. WHAT IS THE COMPANY'S CURRENT ASSESSED NEED FOR ADDITIONAL**
17 **GENERATION CAPACITY OVER THE RAP TO MEET THE PROPOSED 18**
18 **PERCENT PLANNING RESERVE MARGIN?**

19 A. Table JFH-D-1 below summarizes the load and resource balance forecast of
20 summer capacity needs for years 2021-2030 (i.e., the RAP) needed to meet the
21 18 percent planning reserve margin. Two capacity need forecasts are provided

Energy Plan filings.

⁶ See Decision No. C17-0316, at ¶49 and Ordering ¶15 in Proceeding No. 16A-0396E.

1 in Table JFH-D-1: (1) a starting level of need in which the capacity of all currently
 2 operating coal units are included through 2030;⁸ and (2) a capacity need
 3 reflecting the impact of recently announced coal unit retirements ahead of
 4 schedule at Craig 2, Hayden 1, and Hayden 2, respectively. A more detailed
 5 load and resource balance is included in Section 2.12 of ERP Volume 2.

6 **Table JFH-D-1 Generation Capacity Needs (MW)**
 7 (needs as of summer of year shown)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Starting Capacity Need long/(short)	102	296	210	61	17	(203)	(672)	(1,354)	(1,411)	(1,474)
Announced early coal retirements:										
Craig 2									(40)	(40)
Hayden 1									(135)	(135)
Hayden 2								(98)	(98)	(98)
Capacity Need with announced retirements long/(short)	102	296	210	61	17	(203)	(672)	(1,452)	1,684	(1,747)

8 **Q. DOES THE LOAD AND RESOURCE BALANCE IN TABLE JFH-D-1 REFLECT**
 9 **THE CAPACITY NEEDS ASSOCIATED WITH THE COMPANY’S COAL**
 10 **TRANSITION AS PART OF THE PREFERRED CLEAN ENERGY PLAN?**

11 A. Yes.⁹ The Company’s preferred CEP includes the retirements of Craig 2,
 12 Hayden 1, and Hayden 2 earlier than currently scheduled, and the capacities for
 13 those respective facilities have been included in the need demonstrated above.

⁷ DSM includes energy efficiency, demand response, and interruptible programs.
⁸ Table JFH-D-1 includes only Public Service’s share of Comanche 1, Craig 2, Hayden 1 and Hayden 2.
⁹ The capacity needs projected in Table JFH-D-1 are calculated assuming the 72 MW Hartsel solar facility (34 MW ELCC) is successfully brought on-line by December 31, 2022. At the time of this filing, Park County has denied necessary permits for the project to proceed to construction. The Company will continue to monitor this situation and if needed, remove the project MWs from the Phase II L&R calculation of capacity needs.

1 However, the preferred CEP retains the same level of generation capacity for
2 Pawnee (505 MW) and Comanche 3 (500 MW Company share) through 2030.

3 **Q. HOW DO THE RESOURCE NEEDS IN TABLE JFH-D-1 ABOVE, WHICH**
4 **FOCUS ON SUMMER PEAK LOADS, COMPARE WITH RESOURCE NEEDS**
5 **BASED ON WINTER PEAK LOADS?**

6 A. From a winter capacity need perspective, our assessment shows no capacity
7 needs for years 2021-2026 with increasing needs each year from 2027-2030.

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

10 A. Yes. Public Service will, prior to receipt of proposals in the 2021 ERP Phase II
11 competitive acquisition process, update the load and resource balance using the
12 most current forecasts of peak demand and generation supply—as well as any
13 resource-related impacts of the Commission’s Phase I decision or other pending
14 proceedings. The RAP capacity needs that will be identified in that updated load
15 and resource balance will establish the level of additional generation resources to
16 be acquired through the Phase II competitive acquisition process to meet the
17 Company’s resource need, inclusive of a planning reserve margin of 18 percent.
18 By updating the load and resource balance in this manner, the Company will
19 better ensure that we acquire a sufficient amount of generation resources to
20 reliably serve the peak demands during the RAP.

1 **Q. HAS THE COMPANY USED A SIMILAR APPROACH IN PRIOR ERP**
2 **PROCESSES?**

3 A. Yes. This approach to update the load and resource balance prior to the Phase
4 II competitive acquisition process is consistent with the approach taken in the
5 2007, 2011, and 2016 ERPs. However, the acquisition of additional resources to
6 meet our capacity needs in the RAP of this resource plan is just part of the
7 picture; the more impactful driver of resource needs in the RAP are associated
8 with the need to achieve the emission reduction targets of SB 19-236, as I
9 discuss in the next section of my Direct Testimony.

10 **B. Generation Needed to Reduce Emissions**

11 **Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL**
12 **GENERATION RESOURCES ARE NEEDED TO COMPLY WITH THE 80**
13 **PERCENT CLEAN ENERGY TARGET ESTABLISHED IN SB 19-236?**

14 A. We used the EnCompass computer model to develop a set of optimized
15 indicative resource plan portfolios that would meet the projected resource needs
16 of the Company for years 2021-2030 along with the estimated costs of those
17 plans over a 2021-2055 planning period. These portfolios were optimized to
18 meet the Company's planning reserve margin target (and other reliability
19 requirements) *and* achieve the 80 percent emission reduction by 2030 from 2005
20 levels, using the baseline and target established by the Colorado Department of
21 Public Health and Environment's Air Pollution Control Division and explained in
22 more detail by Company witness Ms. Lauren W. Quillian. We refer to these
23 portfolios as Clean Energy Plan or CEP portfolios. Portfolios were developed

1 using two different assumptions for the cost of carbon emissions: (1) the social
2 cost of carbon as delineated in SB 19-236 and explained in more detail by
3 Company witness Mr. Jon T. Landrum; and (2) a \$0/ton assumption. A detailed
4 discussion on how these indicative resource portfolios were developed is
5 included in Section 2.13 of ERP Volume 2. With this approach we have captured
6 two different planning paradigms, one with a cost placed on carbon emissions,
7 and one where there is no cost placed on carbon emissions.

8 **Q. HOW DID THE COMPANY REFLECT ESTIMATES FOR THE COST AND**
9 **PERFORMANCE OF FUTURE GENERATION RESOURCES THAT COULD BE**
10 **ADDED TO THE SYSTEM THROUGH THE PHASE II PROCESS IN THESE**
11 **INDICATIVE PORTFOLIOS?**

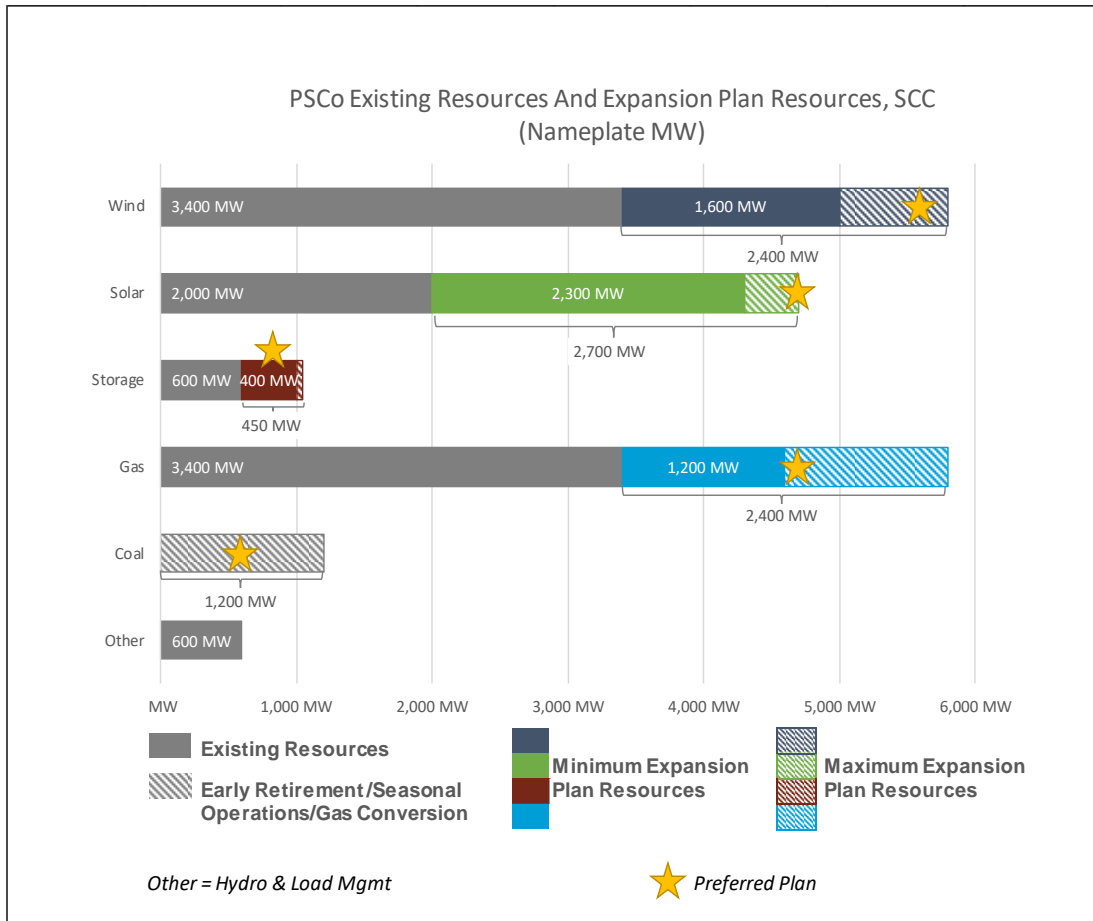
12 A. We developed a suite of what we refer to as “generic resource” representations
13 to serve as proxies for actual bids the Company might expect to receive in the
14 Phase II competitive solicitation. I discuss these generic resources in more detail
15 later in my testimony.

16 **Q. WHAT WERE THE RESULTS OF THE COMPANY’S ASSESSMENT OF**
17 **RESOURCES NEEDED TO ACHIEVE 80 PERCENT CO2 EMISSION**
18 **REDUCTIONS BY 2030?**

19 A. Indicative resource portfolios developed using the SCC included approximately:
20 1,800-2,400 MW of additional wind generation resources; 2,400-2,700 MW of
21 additional solar generation resources (inclusive of both distributed solar and
22 utility scale solar); 400 MW of additional storage resources; and 1,500-2,300 MW
23 of new firm fueled and flexible dispatchable generation resources. The additional

1 resources of the Company’s preferred CEP portfolio (SCC 7) includes
 2 approximately: 2,300 MW of wind; 1,200 MW of distributed solar; 1,600 MW of
 3 utility scale solar; 400 MW of storage; and 1,300 MW of additional firm fueled and
 4 flexible dispatchable generation. I discuss the results of our analysis of ERP and
 5 CEP portfolios later in my testimony, but I think Figure JFH-D-1 below duplicated
 6 from Ms. Alice K. Jackson’s Direct Testimony provides a helpful illustration as to
 7 the portfolios we looked at and where the preferred plan falls:
 8

FIGURE JFH-D-1



1 **Q. WHY DO YOU REFER TO THESE PORTFOLIOS DEVELOPED USING THE**
2 **ENCOMPASS MODEL AS “INDICATIVE”?**

3 A. The ERP and CEP portfolios presented in Phase I of this proceeding were
4 developed using “generic” representations¹⁰ for the cost and performance of
5 wind, solar, storage, gas combustion turbine (“CT”), and gas combined cycle
6 (“CC”) generation technologies. These generic representations are used in the
7 Phase I modeling as a proxy for actual bids that the Company might receive in
8 the Phase II competitive solicitation process that will take place in a year or so.
9 As a result, ERP and CEP portfolios built from generic resources are referred to
10 as “indicative.” The timing, total nameplate amounts, and mix of new wind, solar,
11 storage, gas CTs, and gas CCs in these indicative portfolios will undoubtedly
12 change in the Phase II process when ERP and CEP portfolios are developed
13 from actual bids with actual locations versus generic resource representations
14 with no implied location. As in the last ERP cycle, and as explained in more
15 detail by Company witness Ms. Jackson, we saw unexpected and cost-effective
16 bids for solar plus storage technologies in the 2016 ERP Phase II competitive
17 solicitation. I would expect to see similar outcomes and continued innovation
18 and progress with resource technologies and pricing in Phase II of this ERP.
19 Generally speaking, I expect the Phase II portfolios to include total nameplate

¹⁰ See ERP Volume 2, Section 2.14 for a description of the cost and performance characteristics of the generic resources.

1 amounts that are directionally consistent with the levels of renewables, storage,
2 and dispatchable resources included in the indicative Phase I portfolios.¹¹

3 **C. The Need for Flexible Generation Resources**

4 **Q. HOW HAS THE COMPANY ASSESSED THE NEED FOR FLEXIBLE**
5 **RESOURCES TO HELP INTEGRATE WIND GENERATION ONTO THE**
6 **COMPANY'S ELECTRIC SYSTEM?**

7 A. The Company updated its analysis of Flex Reserve to accommodate current and
8 incremental wind generation on its system. Company witness Mr. Kent L. Scholl
9 discusses the details of this study work in his Direct Testimony. I will refer to this
10 study report as the "2020 Flex Reserve Study."

11 **Q. WERE THE RESULTS OF THE 2020 FLEX RESERVE STUDY**
12 **INCORPORATED INTO THE MODELING OF ERP AND CEP PORTFOLIOS?**

13 A. Yes. When optimizing ERP and CEP portfolios with the EnCompass model, one
14 of the inputs captured in that modeling was a requirement that ERP and CEP
15 portfolios contain the levels of flexible generation resources identified in the 2020
16 Flex Reserve Study work as a function of the total amount of wind generation
17 (both existing and new) contained in each portfolio. Company witness Mr.
18 Landrum discusses how this was accomplished in his Direct Testimony.

¹¹ Phase II portfolios are also expected to include levels of accredited capacity (i.e., ELCC) that are directionally consistent with the levels in the indicative Phase I portfolios.

1 **Q. WILL THE RESULTS OF THE 2020 FLEX RESERVE STUDY BE**
2 **INCORPORATED INTO THE PHASE II ERP AND CEP PORTFOLIOS THAT**
3 **ARE DEVELOPED FROM ACTUAL BIDS?**

4 A. Yes. The Commission's Phase I decision regarding this study will be
5 incorporated into ERP and CEP portfolios developed in the Phase II process.

6 **D. Dispatchable Resource Needs for System Reliability**

7 **Q. HOW HAS THE COMPANY ASSESSED THE NEED FOR DISPATCHABLE**
8 **GENERATION RESOURCES TO HELP ENSURE THE GENERATION FLEET**
9 **RETAINS THE ABILITY TO CONTINUALLY SERVE CUSTOMER LOAD?**

10 A. The term dispatchable generation in this context refers to generation resources
11 that system operators can start anytime, day or night. The output of these
12 generation resources can be ramped up or down as needed—i.e., dispatched—
13 and can operate continuously for many days regardless of local meteorological
14 conditions.

15 The need to maintain a sufficient amount of dispatchable generation
16 resources was assessed through the following efforts:

- 17 1. Within the EnCompass modeling of ERP and CEP portfolios, operating
18 reserve requirements and flex reserve requirements were input directly
19 into the model to maintain a continued balance between hourly customer
20 load and generation. As Mr. John T. Welch details in his Direct
21 Testimony, the Company's Commercial Operations group conducted
22 significant analysis of the hourly generation output from these EnCompass
23 runs to ensure that the modeled operation of the Company's generation
24 and storage resources were realistic and that the various reserve
25 requirements were being adequately enforced by the model.
- 26 2. ERP Volume 2 (Section 2.11) documents a recent four-day long weather
27 event in November 2015 in Colorado with virtually no wind generation
28 output and significantly reduced solar generation output. That analysis

1 shows that, in the extreme scenario where there was no dispatchable
2 generation available to the system, approximately 69,000 MW of 5-hour
3 storage¹² would have been required to serve customer net load (net load =
4 native load – renewable generation). By contrast, the analysis also shows
5 that approximately 1,000 MW of 5-hour storage would have been required
6 to serve customer net load if approximately 3,900 MW of dispatchable
7 generation were available. This simple analysis shows that a combination
8 of intermittent renewable, short-duration storage, and dispatchable
9 generation work together efficiently to reliably meet customer load.

10 **E. The Need for Additional Resources to Comply with the RES**

11 **Q. HOW DID PUBLIC SERVICE ASSESS WHETHER ADDITIONAL RENEWABLE**
12 **RESOURCES ARE NEEDED TO COMPLY WITH THE “MINIMUM AMOUNTS”**
13 **REFLECTED IN THE PERCENTAGE REQUIREMENTS OF THE RES?**

14 A. We did so by comparing the forecast of wholesale distributed generation (“DG”)
15 (i.e., DG resources over 30 MW in nameplate capacity) and non-DG Renewable
16 Energy Credits (“RECs”) over time with the minimum percentage requirements in
17 the RES statute and RES Rules. This comparison shows that the existing and
18 planned wholesale DG and non-DG renewable resources will generate enough
19 RECs to comply with the minimum amounts in the RES beyond 2030. Details
20 about the Company’s REC projections to meet the Retail DG requirement are
21 included in the 2020-2021 RE Plan that was filed with the Commission on July 1,
22 2019 in Proceeding No. 19A-0369E.

23

¹² The results of the analysis were presented on a basis of 5-hour duration storage to align with the storage duration of the Company’s existing Cabin Creek pumped hydro facility.

1 **V. DEVELOPMENT OF PHASE I ERP AND CEP PORTFOLIOS**

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

3 A. The purpose of this section of my Direct Testimony is to explain how we
4 developed the ERP and CEP portfolios for purposes of this Phase I filing.

5 **Q. BEFORE GOING INTO DETAIL ABOUT THE DEVELOPMENT PROCESS,**
6 **WHAT IS AN ERP PORTFOLIO AND WHAT IS A CEP PORTFOLIO?**

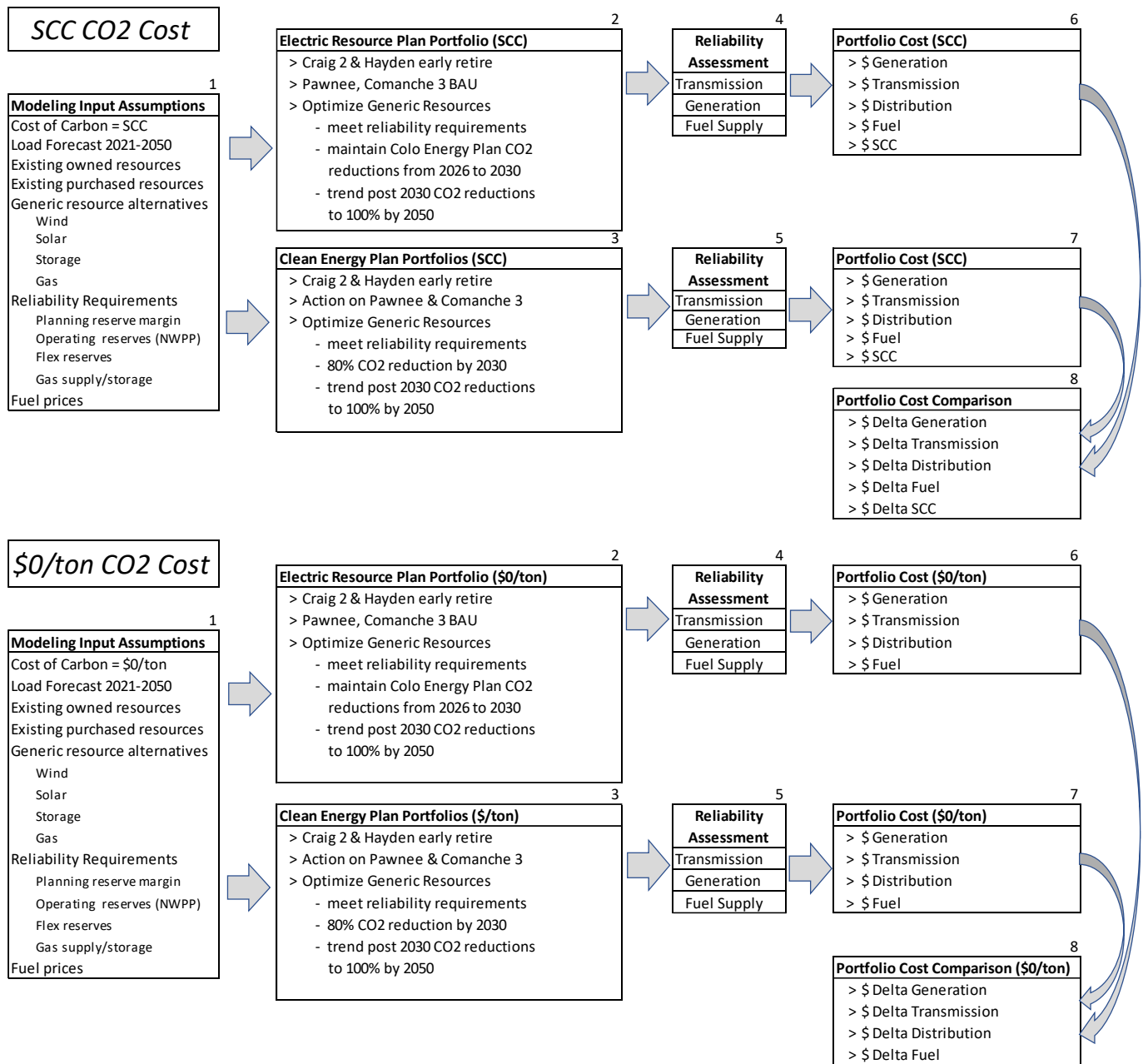
7 A. As I described briefly above, we developed ERP portfolios to meet the reference
8 case need, i.e., the needs reflected in our load forecast inclusive of the
9 previously announced accelerated retirements of Craig 2, Hayden 1, and Hayden
10 2. ERP portfolios are not required to meet the clean energy target within the
11 modeling in 2030 for SB 19-236. In contrast, CEP portfolios reflect additional
12 coal actions at Pawnee and Comanche 3 and additional resource acquisitions
13 that are required to meet the 80 percent clean energy target established by SB
14 19-236. We applied similar portfolio distinctions in the last ERP cycle where we
15 had Colorado Energy Plan portfolios that replaced Comanche 1 and Comanche 2
16 and portfolios that met a resource need assuming those units stayed online
17 through the end of their book lives. We have in large part replicated the same
18 approach here, consistent with the directives of SB 19-236.

1 **Q. PLEASE DESCRIBE THE GENERAL PROCESS THE COMPANY EMPLOYED**
2 **IN DEVELOPING THE ERP AND CEP PORTFOLIOS THAT ARE PRESENTED**
3 **IN THIS PHASE I PROCEEDING.**

4 A. We used the EnCompass computer model to develop a set of optimized resource
5 plan portfolios that would meet the Company's projected resource needs and
6 reliability requirements while reducing carbon emissions by at least 80 percent by
7 2030. These portfolios were optimized under two different assumptions for the
8 cost of carbon emissions, as described above: (1) portfolios using the SCC; and
9 (2) portfolios using a \$0/ton carbon cost assumption. Figure JFH-D-2 below
10 provides a high-level illustration as to the Company's analysis framework for
11 creating these portfolios, and a detailed discussion on this process is included in
12 Section 2.13 of ERP Volume 2.

1

Figure JFH-D-2 ERP and CEP Portfolio Analysis



2 **Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN AN ERP OR CEP**
 3 **PORTFOLIO.**

4 **A.** An ERP or CEP portfolio contains all the information needed to represent the
 5 characteristics and composition of the Public Service electric generation fleet for

1 a given set of future assumptions for years 2021-2055. Some of the key
2 assumptions are as follows:

- 3 1. A forecast of future electric customer load (wholesale and retail);
- 4 2. The cost, performance, and emission projections for existing generating
5 units;
- 6 3. The cost, performance, and emission projections for potential future
7 generation resource additions:
- 8 4. Forecasted fossil fuel prices;
- 9 5. Total system emission projections;
- 10 6. An estimate of cost for new transmission investment (recognizing that
11 additional transmission investment will be necessary to interconnect
12 portfolios evaluated in Phase II once generation locations are noted); and
- 13 7. Annual system revenue requirements.

14 **Q. PLEASE DESCRIBE THE COAL ACTIONS THAT WERE CONSIDERED IN**
15 **THE RESPECTIVE PORTFOLIOS.**

16 A. I addressed this earlier in this section of my Direct Testimony but provide
17 additional detail here. Both the ERP and CEP portfolios include the recently
18 announced accelerated retirements of Craig 2 in 2028, Hayden 1 in 2028, and
19 Hayden 2 in 2027. The Company also performed EnCompass modeling to
20 inform the costs and benefits of the decisions to retire Craig 2 and Hayden 1 and
21 2 ahead of their scheduled business as usual (“BAU”) retirement dates, as
22 discussed in Section 2.13 of Volume 2. For the two remaining Company coal
23 units, Pawnee and Comanche 3, all ERP portfolios assume continued operation

1 of these coal units to 2041 and 2069, respectively (denoted as BAU below).¹³ In
 2 contrast, CEP portfolios assess different combinations of coal actions on Pawnee
 3 and Comanche 3 as illustrated by combined or paired actions 2 through 8 in
 4 Table JFH-D-2. The various actions include combinations of accelerated
 5 retirements, gas conversions, and reduced operations beginning in 2030. By
 6 combining these actions in different ways, we have provided a diverse set of
 7 carbon emission reduction pathways toward the 2030 clean energy target.

8 **Table JFH-D-2 Pawnee and Comanche 3 Actions**

Paired Action	Pawnee				Comanche 3				
	Early Retire EOY 2028	Convert to Gas EOY 2027	Convert to Gas EOY 2024	BAU	Early Retire EOY 2029	Early Retire EOY 2039	Convert to Gas EOY 2027	Early Retire EOY 2039, Reduced Operations starting 2030	BAU
1				X					X
2	X				X				
3	X							X	
4		X					X		
5		X			X				
6		X				X			
7		X						X	
8			X					X	

9 **Q. PLEASE DESCRIBE HOW CARBON EMISSIONS WERE REPRESENTED OR**
 10 **LIMITED IN THE CEP PORTFOLIOS?**

11 A. All CEP portfolios were required to meet at—a minimum—the 80 percent clean
 12 energy target by 2030, while ERP portfolios were not required to do so. Both
 13 ERP and CEP portfolios were also required to achieve a 100 percent emission

¹³ The revenue requirements for Comanche 3 for the 2021-2055 planning period modeled in EnCompass are based off depreciating the unit to a 2070 retirement date.

1 reduction by year 2050. Put another way, all portfolios are carbon-free by
2 2050—but the CEP portfolios achieve earlier reductions through additional
3 actions on the coal fleet prior to 2030. Company witness Mr. Landrum discusses
4 the modeling of emission constraints in his Direct Testimony.

5 **Q. WHY DID THE COMPANY DEVELOP ERP PORTFOLIOS THAT DO NOT**
6 **ACHIEVE THE 80 PERCENT CLEAN ENERGY TARGET ESTABLISHED IN**
7 **SB 19-236?**

8 A. ERP portfolios were needed for two primary reasons: (1) to provide a plan that
9 focused on meeting the resource needs of the system absent the clean energy
10 target, referred to herein as a “base need” or “ERP” portfolio; and (2) to serve as
11 a cost foundation against which the costs and benefits of CEP portfolios are
12 compared. The ERP portfolio concept is also helpful, as explained by Company
13 witness Mr. Alexander G. Trowbridge, for purposes of establishing cost recovery
14 through the statutory Clean Energy Plan Rider (“CEPR”).

15 **Q. HOW DID THE COMPANY REFLECT ESTIMATES FOR FUTURE SUPPLY-**
16 **SIDE GENERATION RESOURCES IN THESE INDICATIVE PORTFOLIOS?**

17 A. ERP and CEP portfolios were developed within EnCompass from a suite of what
18 we refer to as “generic resource” representations to serve as proxies for potential
19 new supply-side generation resources, without regard to a specific location.
20 These generic resource representations are meant to be indicative of what the
21 Company might expect to receive in the Phase II competitive solicitation for this
22 2021 ERP & CEP. Generic resource representations were developed for wind,
23 utility-scale solar, four-hour duration battery storage, gas-fired combined cycle,

1 gas-fired combustion turbine (sometimes referred to as “simple cycle”), and gas-
2 fired reciprocating engine technology. Wind, solar, and storage estimates were
3 developed from the 2020 National Renewable Energy Laboratory Annual
4 Technology Baseline. Gas-fired estimates were developed by employees within
5 the Company’s engineering and construction department. Detailed information
6 on the generic resource representations is contained in Section 2.14 of ERP
7 Volume 2.

8 **Q. HOW WERE SYSTEM RELIABILITY REQUIREMENTS FACTORED INTO THE**
9 **DEVELOPMENT OF ERP AND CEP PORTFOLIOS?**

10 A. As discussed in Section 2.9 of Volume 2, system reliability was factored into the
11 development of portfolios in an iterative process that involved inputting various
12 reliability requirements upfront into the EnCompass modeling process, post-
13 modeling reliability review of model output/results, and then adjusting model
14 inputs if needed and then rerunning the adjusted model.

15 **Q. PLEASE DESCRIBE WHAT RELIABILITY REQUIREMENTS WERE**
16 **REFLECTED AS INPUTS INTO THE ENCOMPASS MODELING PROCESS.**

17 A. The results of technical studies regarding planning reserve requirements, flex
18 reserve requirements, and ELCC capacity credit were applied within the
19 EnCompass modeling of all portfolios.¹⁴ In addition to the results of these
20 technical studies, the operating requirements established by the Northwest

¹⁴ See ERP Volume 2, Section 2.18 for these studies.

1 Power Pool (“NWPP”) Reserve Sharing Group were reflected as inputs into the
2 modeling process.¹⁵

3 **Q. PLEASE DESCRIBE THE POST-MODELING RELIABILITY REVIEW**
4 **PROCESS.**

5 A. This process involved reviewing hourly model output for year 2030. A team of
6 Company subject matter experts reviewed the overall generation composition of
7 portfolios from both a generation reliability perspective and a transmission
8 reliability perspective.

9 **Q. PLEASE BRIEFLY DESCRIBE THE GENERATION RELIABILITY REVIEW**
10 **PROCESS.**

11 A. The hourly data review process for generation reliability involved an assessment
12 of 8760 (i.e., the number of hours in a year) hourly model output to determine if
13 the model was properly enforcing planning reserve, flex reserve, and NWPP
14 operating reserve requirements. The review also analyzed whether the current
15 gas supply system would be sufficient to reliably supply the hourly volumes and
16 fluctuations in gas burns that the modeling predicted.

17 **Q. PLEASE BRIEFLY DESCRIBE THE TRANSMISSION RELIABILITY REVIEW**
18 **PROCESS.**

19 A. The hourly data review process for real-time transmission reliability also involved
20 an assessment of 8760 hourly model output. The purpose of the review was to
21 determine if the current and planned transmission system could reliably deliver,

¹⁵ As a member of the Northwest Power Pool (“NWPP”) Reserve Sharing Group, Public Service carries operating reserves in accord with the NWPP established methodology.

1 in real-time, the output of the generation resources in each portfolio to customer
2 load. In addition to this real-time assessment of hourly data, the Company's
3 transmission reliability review and planning process to support this 2021 ERP &
4 CEP filing involved an assessment of the Company's resource planning
5 projections to determine if the planned transmission system expansion could
6 reliably deliver the Company's resource acquisition target to meet the 2030
7 emission reduction goals.¹⁶ Company witness Mr. Hari Singh discusses this
8 assessment in his Direct Testimony.

9 **Q. PLEASE DESCRIBE THE ITERATIVE NATURE OF THE RELIABILITY**
10 **REVIEW AND HOW THE RESULTS OF THOSE REVIEWS INFORMED THE**
11 **MODELING PROCESS.**

12 A. If these reliability reviews identified that a particular reliability input requirement
13 needed adjusting, then the adjustments would be made, the model would be
14 rerun, and the output would be reviewed to see if the adjustment worked as
15 intended. For example, if certain generating units were viewed as contributing
16 more spinning reserves than they should or could, the modeling inputs that
17 define a generating unit's contribution to spin would be adjusted and the model
18 would be rerun. In addition, there are certain aspects of this type of modeling
19 that are a function of the model output and therefore cannot be fully captured
20 through the various upfront inputs into the model. For example, the required
21 transmission upgrades that might be needed to reliably deliver the new

¹⁶ This planned transmission eventually became the Colorado's Power Pathway project that the Company filed a CPCN for on March 2, 2021.

1 generation resources that were added to the system as a result of the
2 optimization cannot be known until after the model is run. In this instance, the
3 cost for any additional transmission requirements would be a post-modeling
4 addition to the cost of the portfolio.

5 **Q. HOW WERE THE OVERALL COSTS OF THE ERP AND CEP PORTFOLIOS**
6 **DEVELOPED, REPRESENTED, AND COMPARED?**

7 A. Each portfolio contains projections for the cost of all generators modeled for that
8 particular portfolio, the costs associated with the operation and dispatch of those
9 generators to reliably serve customer load, and projections of the cost for
10 transmission needed to deliver the output of the generation fleet to load. Each of
11 these cost categories are separately calculated and tracked within the
12 EnCompass model. Portfolio costs are provided in two general manners: (1) on
13 a present value or revenue requirement basis over a specified time period; and
14 (2) as a percent change to total customer rates. The incremental costs of CEP
15 portfolios are represented as incremental to the ERP portfolio costs, with the
16 ERP portfolio costs serving as the reference case costs.

17 **Q. WHAT LEVEL OF DSM AND CUSTOMER CHOICE PROGRAMS WAS**
18 **REFLECTED IN THESE ERP AND CEP PORTFOLIOS?**

19 A. The level of DSM included in the portfolios is consistent with the level of DSM
20 resources that the Commission established in the DSM Strategic Issues filing,
21 Proceeding No. 17A-0462EG. Growth beyond 2023, the final year of
22 achievements established in that proceeding, reflects the Company's forecast of
23 future achievements subject to approval as part of a future DSM Strategic Issues

1 proceeding. The level of distributed energy resources represented in the
2 portfolios is consistent with those levels approved as part of the RE Plan in
3 Proceeding No. 19A-0396E.¹⁷ Growth beyond those approved years was
4 forecasted at approximately 105 MW per year. Company witness Mr. Jack W.
5 Ihle discusses the interconnection of these filings in the ERP process further in
6 his Direct Testimony.

7 **Q. DOES THE COMPANY INTEND TO ACQUIRE ANY DSM RESOURCES OR**
8 **CUSTOMER CHOICE SOLAR PROGRAMS, IN PHASE II OF THIS 2021 ERP?**

9 A. No. As a practical matter, the amount of DSM and customer choice that Public
10 Service will acquire over time are proposed and adjudicated in stand-alone
11 proceedings separate from the ERP. Company witness Mr. Ihle discusses this
12 segmentation of planning and acquisition, as well as the interaction with the ERP
13 process, in more detail.

14 **Q. IF THE COMPANY DOES NOT INTEND TO ACQUIRE DSM RESOURCES OR**
15 **CUSTOMER CHOICE PROGRAMS THROUGH THE PHASE II PROCESS OF**
16 **THIS 2021 ERP, THEN WHY IS IT INCLUDED IN THE ANALYSIS OF**
17 **ALTERNATIVE PLANS?**

18 A. DSM and customer choice programs are included because, in assessing the
19 need for additional generation resources and the potential customer cost/savings
20 impacts of those additions, it is important to account for all sources of future DSM
21 achievements as well as all sources of future generation supply that are likely to

¹⁷ Proceeding No. 19A-0396E specifically approved the annual capacity targets for the Solar*Rewards® and Solar*Rewards Community® programs.

1 be added through proceedings other than the 2021 ERP. In this regard, the ERP
2 process represents an integrated view of how these various activities function
3 together to serve the electric supply needs of our customers. For example, when
4 assessing in an ERP whether additional generation capacity is needed to
5 maintain an acceptable level of reliability, it is important to include all sources of
6 generation supply (both existing and planned) as well as all sources of DSM
7 within that assessment. In doing so, we better ensure that any additional
8 generation capacity acquired through the ERP is in fact needed for purposes of
9 maintaining acceptable overall system reliability.

10 **Q. DID THE COMPANY PERFORM A BENCHMARKING ANALYSIS AS PART OF**
11 **THIS ERP?**

12 A. Yes. The topic of benchmarking analysis was discussed extensively in the ERP
13 rulemaking proceeding (Proceeding No. 19R-0096E). Although no rules have
14 been finalized through this process, the Company moved forward consistent with
15 the general direction of the benchmarking proposal in the rulemaking proceeding.
16 It is the Company's understanding that the objective of the benchmarking
17 analysis is to identify, through a static economic screening process¹⁸ using
18 levelized cost representations, whether existing supply-side resources (with an
19 emphasis on existing coal units) greater than 20 MW are cost-effective compared
20 to alternatives available in the market. In the event such resources are identified

¹⁸ A static screening analysis would typically be performed in a spreadsheet and would not require computer-based modeling which involves dynamic analysis of the larger Public Service system.

1 through benchmarking, further study of the costs and benefits of early retiring
2 those resources could be warranted.

3 **Q. WHAT WOULD THIS “FURTHER STUDY” WORK ENTAIL?**

4 A. For Company-owned resources, further study work would entail computer
5 modeling (i.e., dynamic analyses) that would consider a variety of factors
6 associated with early retirement of a generating asset. These factors would
7 include analysis of incremental depreciation expenses and estimated operational
8 and capital savings from the unit, as well as the cost associated with replacement
9 resource capacity and energy and costs associated with correcting any system
10 reliability impacts triggered by the accelerated unit retirement. It is not clear to
11 me, however, how these same costs and benefits would be represented in
12 computer modeling of Power Purchase Agreements (“PPA”) that are found to be
13 not cost-effective compared to alternatives in the market. As we benchmark
14 resources, the draft rules contemplate assessing all existing resources, both PPA
15 and Company-owned generators.

16 **Q. WITHOUT A STANDALONE BENCHMARKING EXERCISE, DOES THE**
17 **ENCOMPASS MODELING OF ERP AND CEP PORTFOLIOS CAPTURE**
18 **THESE VARIOUS FACTORS AS THEY RELATE TO EARLY RETIREMENT OF**
19 **THE COMPANY’S REMAINING COAL UNITS?**

20 A. Yes. The EnCompass modeling of ERP and CEP portfolios captures these costs
21 and benefits that would be associated with accelerated retirement of each of the
22 Company’s remaining coal units. Frankly, I think for this 2021 ERP & CEP—
23 setting aside the fact that the benchmarking approach has not been finalized by

1 the Commission—the benchmarking analysis is not particularly instructive here
2 for two reasons. First, the Company is proposing to take action on *all* of its
3 remaining coal generators. Second, the EnCompass portfolio analyses are very
4 detailed in capturing the impacts of early retirement from a system-wide
5 perspective. In fact, the ERP and CEP portfolio analyses go one step further by
6 evaluating a number of different combinations of actions that could be taken with
7 the Pawnee and Comanche 3 units as discussed earlier in my testimony.

8 **Q. WHAT DID THE BENCHMARKING ANALYSIS SHOW WITH REGARD TO**
9 **NON-COAL FIRED EXISTING GENERATING RESOURCES?**

10 A. In general, the analysis showed that the Company’s owned resources over 20
11 MW appear cost-effective for customers as compared to the range of potential
12 market alternatives (represented by generic resources) that may be available in
13 the market. However, the benchmarking exercise does identify several existing
14 wind and solar PPAs that do not appear cost-effective in comparison to potential
15 market alternatives. This PPA outcome is most likely the result of changes in the
16 market price for these technologies between the time they were acquired and
17 today.

18 **Q. WHAT WERE THE RESULTS OF THE ASSESSMENT OF POTENTIAL COST-**
19 **EFFECTIVE EARLY RETIREMENTS OF UTILITY-OWNED RESOURCES WITH**
20 **RETIREMENT DATES DURING THE PLANNING PERIOD?**

21 A. The results of this analysis are presented in ERP Volume 2, Section 2.5. The
22 evaluation supports the conclusion that early retirement and accelerated
23 recovery of the existing gas-fired units results in added costs to customers under

1 an assumption of \$0/ton or the SCC. The added costs to customers increase
2 when SCC is included because any loss of gas generation in general will lead to
3 additional coal generation which has roughly twice the CO₂ emissions per unit of
4 energy as gas-fired generation.

5 **Q. HOW HAS THIS ASSESSMENT OF POTENTIAL COST-EFFECTIVE EARLY**
6 **RETIREMENTS FACTORED INTO THE DEVELOPMENT OF ERP AND CEP**
7 **PORTFOLIOS?**

8 A. For the same reasons discussed above regarding the benchmarking analysis,
9 and recognizing that the EnCompass modeling of ERP and CEP portfolios
10 captures the costs and benefits associated with early retirement of the
11 Company's remaining coal units, I do not view the results of this assessment as
12 being particularly instructive for this 2021 ERP & CEP.

13 **Q. WHAT IS YOUR OVERALL CONCLUSION OF THE BENCHMARKING AND**
14 **POTENTIAL COST-EFFECTIVE EARLY RETIREMENT ANALYSES FOR THIS**
15 **2021 ERP?**

16 A. This 2021 ERP & CEP includes the presentation of detailed analyses of multiple
17 CEP portfolios that—through a combination of coal actions (including accelerated
18 retirement of all the Company's remaining coal units) and the addition of high
19 levels of zero-emission resources—meet or exceed the 80 percent CO₂
20 reductions established in SB 19-236. When the ERP rulemaking started in
21 Proceeding No. 19R-0096E several years ago, I understand why the
22 benchmarking and early retirement analysis was a key topic. Given where we
23 are now with this plan, however, I believe that these modeling analyses of CEP

1 portfolios in and of themselves comply with the outcome ultimately contemplated
2 in the rulemaking process.

3

1
2

**Figure JFH-D-3 SCC ERP and CEP Portfolio
 Generic Resource Additions and CO2 Reduction**

Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	-69%	-88%	-85%	-86%	-88%	-81%	-84%	-85%
Resource Additions 2021-2030 (Nameplate MW)								
Wind	1,650	2,350	2,300	2,300	2,300	1,850	2,300	2,350
Utility-Scale Solar	1,150	1,550	1,550	1,500	1,550	1,250	1,550	1,550
Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
Storage	400	450	400	450	400	400	400	400
Firm Dispatchable	1,276	2,352	1,960	1,568	1,764	1,505	1,276	1,233

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3 The categories of resource additions include:

- 4 1. Wind: the nameplate MW of wind resources in each portfolio.
- 5 2. Utility Scale Solar: The nameplate amount of utility-scale solar
6 generation resources in each portfolio.
- 7 3. Distributed Solar: The nameplate amount of distributed solar generation
8 resources in each portfolio.
- 9 4. Storage: The nameplate amount of 4-hour duration utility-scale storage
10 resources in each portfolio.
- 11 5. Firm Dispatchable: The nameplate amount of firm dispatchable resources
12 added in each portfolio.²⁰

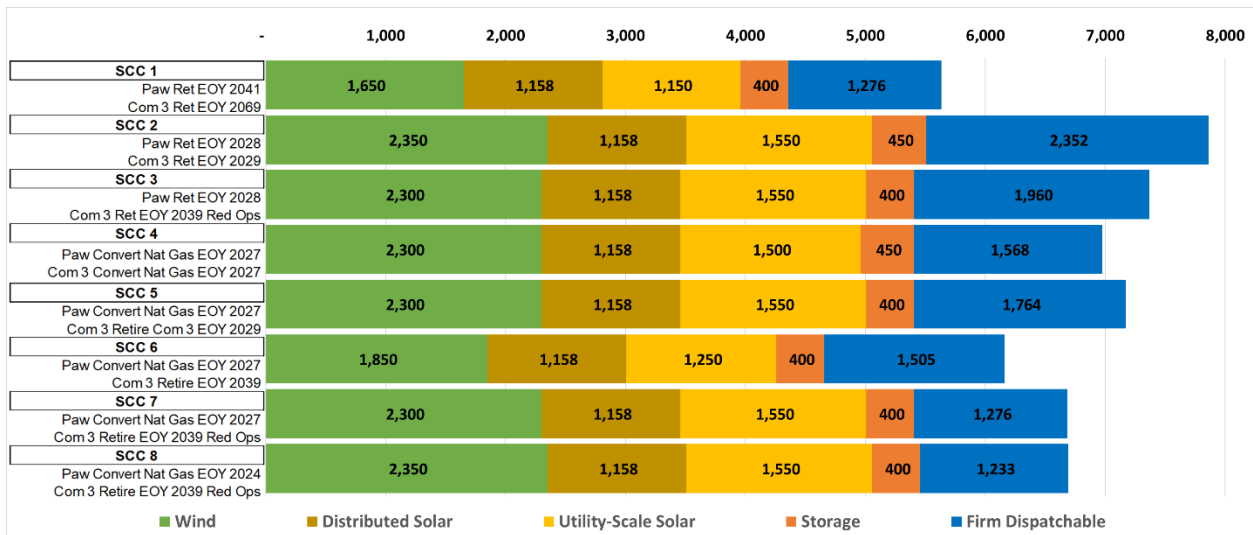
13 The ERP portfolio (SCC 1) includes 1,650 MW of wind and 1,150 MW of
14 utility scale solar resources, which is less than the amount of wind and solar
15 added in the CEP portfolios. The CEP portfolios (SCC 2 through SCC 8) add
16 between 1,850-2,350 MW of nameplate wind and 1,250-1,500 MW of nameplate
17 solar. From an emission reduction perspective, SCC 1 achieves a 69 percent

²⁰ For purposes of the Phase I modeling of ERP and CEP portfolios, generic gas-fired combustion turbine technologies were used to provide these firm dispatchable requirements.

1 emission reduction, while SCC 2 through SCC 8 achieve between 81-88 percent
 2 reductions by 2030.

3 As to firm and flexible dispatchable resources, SCC 1 includes a
 4 comparable amount of firm dispatchable resources at 1,276 MW as SCC 7 and
 5 SCC 8. The remaining SCC portfolios add between 1,500-2,350 MW of firm
 6 dispatchable resources. Figure JFH-D-4 below shows the resource additions of
 7 each ERP and CEP portfolio in graphical format.

8 **Figure JFH-D-4 SCC ERP and CEP Portfolio**
 9 **Nameplate MW Resource Additions 2021-2030**



10 **Q. DID THE COMPANY ESTIMATE THE POTENTIAL INFRASTRUCTURE**
 11 **INVESTMENT ASSOCIATED WITH THE INDICATIVE PORTFOLIOS IN**
 12 **FIGURES JFH-D-3 AND JFH-D-4?**

13 **A.** Yes. Figure JFH-D-5 below shows the estimated generation and transmission
 14 infrastructure associated with the generic resource additions in Figure JFH-D-3
 15 for years 2021-2030. The generation investment values represent the general
 16 level of dollars one could expect to be spent in constructing the generation

resources in each portfolio.²¹ The transmission investment values are reflective of the cost of the Colorado’s Power Pathway project, which the Company filed a CPCN for on March 2, 2021.

**Figure JFH-D-5 SCC ERP and CEP Portfolio
 Infrastructure Investment Potential**

Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Infrastructure Investment Potential (\$M)								
1 Generation 2021-2030 (\$M)	\$ 4,282	\$ 6,223	\$ 5,814	\$ 5,519	\$ 5,650	\$ 4,847	\$ 5,378	\$ 5,360
2 Transmission 2021-2030 (\$M)	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667

Q. WHAT ARE THE PROJECTED COSTS OF THE INDICATIVE PORTFOLIOS IN FIGURE JFH-D-3?

A. Figure JFH-D-6 below includes several metrics to represent the costs and benefits of the clean energy actions in SCC 1 through SCC 8, including:

- The present value of the total annual carbon emissions of each portfolio multiplied by the SCC as established in SB 19-236;
- The PVRR over the entire 2021-2055 planning period (i.e., utility costs given they are representative of what is included in customer bills); and
- PVRR over different portions of the planning period to enable the Commission to see how costs/benefits are distributed over time.

Figure JFH-D-6 below contains different combinations of the present value of carbon emissions and PVRR utility costs.

²¹ Estimated construction costs for the different generic resource technologies can be found in Section 2.14 of ERP Volume 2.

1

Figure JFH-D-6: SCC ERP and CEP Portfolio Projected Costs

Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1 PVRR Utility Cost 2021-2055 (\$M)	\$ 38,814	\$ 39,582	\$ 39,429	\$ 39,373	\$ 39,450	\$ 39,230	\$ 39,306	\$ 39,453
PVRR Utility Cost Delta vs. SCC 1								
2 2021-2030 (\$M)	\$ -	\$ 271	\$ 192	\$ 284	\$ 265	\$ 177	\$ 206	\$ 302
3 2021-2040 (\$M)	\$ -	\$ 951	\$ 621	\$ 622	\$ 786	\$ 387	\$ 479	\$ 591
4 2021-2055 (\$M)	\$ -	\$ 768	\$ 616	\$ 560	\$ 637	\$ 417	\$ 492	\$ 639
5 NPV CO2 2021-2055 (\$M)	\$ 8,625	\$ 6,296	\$ 6,719	\$ 6,295	\$ 6,234	\$ 6,809	\$ 6,646	\$ 6,329
6 PVRR Utility Cost + NPV CO2 2021-2055 (\$M)	\$ 47,439	\$ 45,877	\$ 46,148	\$ 45,669	\$ 45,684	\$ 46,040	\$ 45,951	\$ 45,782
PVRR Utility Cost + NPV CO2 Delta vs. SCC 1								
7 2021-2030 (\$M)	\$ -	\$ (124)	\$ (77)	\$ (271)	\$ (226)	\$ (153)	\$ (158)	\$ (370)
8 2021-2040 (\$M)	\$ -	\$ (1,063)	\$ (970)	\$ (1,410)	\$ (1,289)	\$ (1,112)	\$ (1,185)	\$ (1,389)
9 2021-2055 (\$M)	\$ -	\$ (1,561)	\$ (1,290)	\$ (1,770)	\$ (1,755)	\$ (1,399)	\$ (1,487)	\$ (1,657)

2 **Q. HOW ARE THE INCREMENTAL COSTS/BENEFITS OF CEP PORTFOLIOS**
 3 **MEASURED IN FIGURE JFH-D-6?**

4 A. The incremental costs and benefits of the additional clean energy actions in CEP
 5 portfolios are determined by comparing the PVRR Utility costs and NPV CO2
 6 costs of each CEP portfolio to those of the ERP portfolio. In this instance, the
 7 ERP portfolio serves as a reference case for costing purposes. For example,
 8 when considering *both* the PVRR of utility costs and the NPV of CO2 costs,
 9 SCC2 shows \$124 million in savings compared to SCC 1 over the 2021-2030
 10 timeframe. When considering *only* the PVRR of utility costs, SCC2 shows \$271
 11 million of additional costs compared to SCC 1 over the 2021-2030 timeframe.

12 **Q. DID THE COMPANY TRANSLATE THESE PROJECTED PVRR UTILITY COST**
 13 **IMPACTS INTO PROJECTIONS OF CUSTOMER RATE IMPACTS?**

14 A. Yes. The bottom three rows of Figure JFH-D-7 below show projections of the
 15 average annual increase in retail customer rates for three different portions of the

1 planning period: 2024-2030; 2024-2040; and 2024-2055. Given these are
2 average values for a specific timeframe, in some years the annual rate increase
3 is higher than the average indicated and in other years it is below the average.
4 The Company believes, however, that an average value over the three time
5 periods referenced provides a useful comparison across portfolios.

6 **Q. WHY ARE AVERAGE ANNUAL RATE INCREASES MEASURED STARTING**
7 **IN 2024 VERSUS PVRR COSTS, WHICH BEGIN THE FIRST YEAR OF THE**
8 **PLANNING PERIOD (2021)?**

9 A. The modeling results of ERP and CEP portfolios begin to include clean energy
10 actions in year 2025. Accordingly, the Company felt it appropriate to begin
11 measuring the change in customer rate impacts of such actions from year 2024
12 to 2025. In doing so, the Company differentiates between the rate impacts of
13 clean energy actions in this ERP and the rate impacts of the Colorado Energy
14 Plan in years 2021-2023—during which some of the Colorado Energy Plan
15 resources and related facilities come online.

16

1 **Figure JFH-D-7: SCC ERP and CEP Portfolio Projected Rate Impacts**

Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Average Annual Rate Impact								
1 2024-2030 (%)	2.1%	3.1%	2.8%	2.8%	2.9%	2.4%	2.6%	2.5%
2 2024-2040 (%)	1.5%	1.5%	1.6%	1.5%	1.5%	1.6%	1.5%	1.6%
3 2024-2055 (%)	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%

2 Figure JFH-D-7 shows customer impacts being at their highest levels
 3 between years 2024-2030 when the clean energy actions to achieve the 80
 4 percent emission reduction target are being implemented. While the costs for
 5 clean energy actions to achieve the 80 percent clean energy target continue
 6 beyond 2030, the additional costs year over year tend to decrease, resulting in
 7 lower average annual rate impacts. This is evident by the lower average annual
 8 rate increases for years 2024-2040. For years 2040-2055, both ERP and CEP
 9 portfolios drive toward the carbon-free by 2050 target, adding more renewables
 10 and an assumption of higher fuel prices due to an ever-increasing blend of
 11 hydrogen into the fuel supply of the gas-fired fleet. These modeled actions to
 12 drive toward the carbon-free by 2050 target drive the average annual rate
 13 increases for 2021-2055 up to about 2 percent.

1 **Q. HOW DOES ONE DETERMINE THE TOTAL OR CUMULATIVE PROJECTED**
2 **RATE INCREASE OVER EACH OF THE DIFFERENT TIMEFRAMES IN**
3 **FIGURE JFH-D-7?**

4 A. When taken in isolation assuming all other rate making factors remain constant,
5 total or cumulative rate impacts from the 2021 ERP & CEP can be estimated by
6 multiplying the average annual rate increase by the number of years in each time
7 frame. For example, the total or cumulative rate increase for the 2024-2030
8 timeframe for ERP SCC 1 would be about 12.6 percent. Assuming 2024 retail
9 rates were 10¢s/kWh, 2030 rates would be 11.26¢/kWh. Similarly, the
10 cumulative rate increase for the 2024-2055 timeframe for ERP SCC 1 would be
11 about 52.7 percent. Assuming 2024 retail rates were 10¢s/kWh, 2055 rates
12 would be 15.27¢/kWh. However, this is complicated by actual rate recovery
13 mechanisms available via policy decisions as well as the fact that these
14 decisions cannot be held in isolation or in vacuum when the time comes for
15 actual cost recovery.

16 **Q. GIVEN SB 19-236 ESTABLISHES THE CEPR AT 1.5 PERCENT OF RETAIL**
17 **CUSTOMER BILLS, DO THE AVERAGE ANNUAL RATE INCREASES IN**
18 **FIGURE JFH-D-7 THAT ARE GREATER THAN 1.5 PERCENT INDICATE**
19 **THAT THE ADDITIONAL COSTS OF THESE PLANS WOULD EXCEED A 1.5**
20 **PERCENT CEPR?**

21 A. No. The relevant data point for that issue is the delta or difference in average
22 annual rate increases between SCC 1 versus SCCs 2 through 8 for years 2024-
23 2030, which provides a general indication as to how the additional costs of the

1 CEP portfolios compare with a 1.5 percent CEPR. These deltas for SCC 2
2 through SCC 8 are between 0.3 percent and 0.7 percent more than SCC 1 (both
3 less than a 1.5 percent); therefore, they provide a general indication that the
4 additional costs of the CEP portfolios align with and are absorbed by the revenue
5 stream associated with the CEPR. I describe this as a “general indication”
6 because the average annual rate increases in Figure JFH-D-7 include all costs,
7 including fuel and transmission, both of which are excluded from being recovered
8 through the CEPR and recovered elsewhere (i.e., the Electric Commodity
9 Adjustment and Transmission Cost Adjustment) under the statutory structure. A
10 further assessment of the amount of additional costs that would qualify for CEPR
11 funding would require a more detailed analysis that accounts for these costs
12 elsewhere. A detailed analysis of CEPR costs is included in the Direct
13 Testimony of Company witness Mr. Trowbridge.

14 **Q. DID THE COMPANY DEVELOP A METRIC THAT WOULD ALLOW**
15 **COMPARISON OF THE VARIOUS CARBON REDUCTIONS AND**
16 **ASSOCIATED COSTS OF CEP PORTFOLIOS SCC 2 THROUGH SCC 8?**

17 A. Yes. The Company developed a metric to quantify: (1) the additional 2021-2030
18 costs of CEP portfolio clean energy actions above those of the ERP reference
19 case; and (2) the additional year 2030 carbon reductions achieved above those
20 of the ERP reference case as a result of those additional actions. In short, the
21 metric provides an indication as to how effective or efficient the incremental costs
22 of clean energy actions compare with the incremental carbon reductions brought
23 by those actions. Row 2 of Figure JFH-D-8 below contains this carbon reduction

1 efficiency metric for each of the seven CEP portfolios. Lower \$/ton values are
 2 better, providing a general indication of higher carbon reductions for each
 3 incremental dollar spent. It should be noted that this metric focuses on the front-
 4 end years of each CEP portfolio, years 2021-2030, and does not take into
 5 account incremental costs and associated carbon reductions between CEP and
 6 ERP portfolios for years 2031-2055.

7 **Figure JFH-D-8: SCC ERP and CEP Portfolio CO2% Reduction Efficiency**

	Portfolio	SCC 1	SCC 2	SCC 3	SCC 4	SCC 5	SCC 6	SCC 7	SCC 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP Preferred	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	2030 CO2 % Reduction	-69%	-88%	-85%	-86%	-88%	-81%	-84%	-85%
2	CO2 Reduction Efficiency (\$/ton)	-	\$ 46	\$ 48	\$ 34	\$ 36	\$ 36	\$ 38	\$ 28
3	PVRR Utility Cost Delta vs. SCC 1 2021-2030 (\$M)	\$ -	\$ 271	\$ 192	\$ 284	\$ 265	\$ 177	\$ 206	\$ 302

8 **Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE CO2 REDUCTION**
 9 **EFFICIENCY VALUES FOR CEP PORTFOLIOS IS CALCULATED?**

10 A. Yes. The CO2 Reduction Efficiency values in row 2 of Figure JFH-D-8 are
 11 calculated by taking the PVRR Utility Cost Delta values from row 3 and dividing
 12 by the present value of each CEP portfolios' additional 2030 CO2 tonnage
 13 reductions above those of the ERP reference case. For example, the \$46 value
 14 for SCC 2 is calculated by taking the \$271 million PVRR Utility Costs Delta
 15 versus SCC 1 and dividing by 5.9 MST, which represents the present value of
 16 the additional CO2 reductions each year for years 2021-2030 compared to those
 17 of SCC 1.

1 **Q. HAS THE COMPANY MEET THE REQUIREMENTS OF RULE 3604(K)?**

2 A. Yes. Rule 3604(k) requires “a baseline case that describes the costs and benefits
3 of the new utility resources required to meet the utility’s needs...”. Our SCC 1
4 portfolio, sometimes called the ERP or reference case, meets the requirements
5 of that portion of the rule. The rule goes on to require alternate combinations of
6 resources including “proportionately more” renewable energy resources,
7 demand-side resources, energy storage systems, or Section 123 resources.
8 The Company has modeled and presented numerous portfolios across two
9 general sets of outcomes driven by the inclusion or exclusion of the SCC as a
10 model input. These portfolios produce a varied set of renewable resource and
11 energy storage outcomes. Specifically, wind varies from 1,000 MW up to 2,350
12 MW of new additions in the RAP. Utility-scale solar addition outcomes vary
13 between 100 MW and 1,550 MW. Storage addition outcomes vary between 50
14 MW and 450 MW. I note that the Company has not modeled varying amounts of
15 Section 123 resources in this Phase I filing; while we think, as Company witness
16 Mr. Ihle explains in his Direct Testimony, that the Section 123 mechanism offers
17 possibilities for technology advancement, the potential types of Section 123
18 resources are too diverse and un-defined to practicably model them for purposes
19 of this Phase I. We anticipate receiving innovative Section 123 bids in Phase II
20 and will evaluate them accordingly. Further, we interpret Rule 3604(k) and its
21 “or” phrasing to allow a significant amount of flexibility in the resources that the
22 Company provides “proportionately more” of, and again, we have provided a
23 varied set of renewable and storage outcomes in this Phase I filing, as I have

1 shown in my Direct Testimony. In addition, the Company also has provided eight
2 different sensitivities for the purpose of testing the robustness of the alternate
3 plans under various parameters.

4

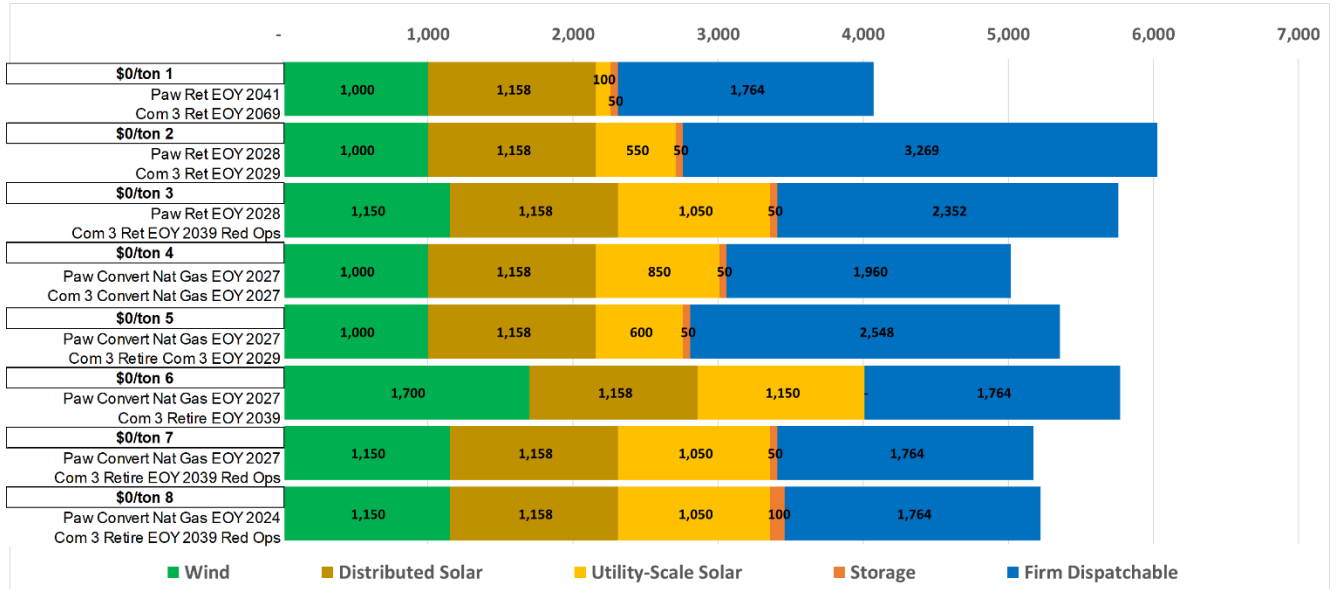
**Figure JFH-D-9: \$0/ton ERP and CEP Portfolio
 Generic Resource Additions and CO2 Reduction**

Portfolio	\$0/ton 1	\$0/ton 2	\$0/ton 3	\$0/ton 4	\$0/ton 5	\$0/ton 6	\$0/ton 7	\$0/ton 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
2030 CO2 % Reduction	-63%	-81%	-81%	-81%	-81%	-81%	-81%	-81%
Resource Additions 2021-2030 (Nameplate MW)								
Wind	1,000	1,000	1,150	1,000	1,000	1,700	1,150	1,150
Utility-Scale Solar	100	550	1,050	850	600	1,150	1,050	1,050
Distributed Solar	1,158	1,158	1,158	1,158	1,158	1,158	1,158	1,158
Storage	50	50	50	50	50	-	50	100
Firm Dispatchable	1,764	3,269	2,352	1,960	2,548	1,764	1,764	1,764

ERP portfolio \$0/ton 1 includes 1,000 MW of wind and 100 MW of utility scale solar resources, while CEP portfolios \$0/ton 2 through \$0/ton 8 add between 1,000-1,700 MW of nameplate wind and 550-1,150 MW of nameplate solar. From a carbon reduction perspective, \$0/ton 1 achieves a 63% CO2 reduction while \$0/ton 2 through \$0/ton 8 all achieve emission reductions of approximately 81 percent by 2030. From a firm and flexible dispatchable resource perspective, \$0/ton 1, 6, 7, and 8 include 1,764 MW of firm dispatchable resources. The remaining \$0/ton portfolios add between 1,960-3,269 MW of firm dispatchable resources. Figure JFH-D-10 below shows the resource additions of each ERP and CEP portfolio in graphical format.

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Figure JFH-D-10: \$0/ton ERP and CEP Portfolio Nameplate MW Resource Additions 2021-2030



3 **Q. WHAT ARE THE ESTIMATED INFRASTRUCTURE INVESTMENTS**
 4 **ASSOCIATED WITH THE PORTFOLIOS IN FIGURE JFH-D-8?**

5 A. Figure JFH-D-11 below shows the estimated generation and transmission
 6 infrastructure associated with the generic resource additions in Figure JFH-D-9
 7 for years 2021-2030. The generation investment values represent the general
 8 level of dollars one could expect to be spent in constructing the generation
 9 resources in each portfolio.²³ The transmission investment values are reflective
 10 of the cost of the Colorado’s Power Pathway Project, for which the Company filed
 11 a CPCN for on March 2, 2021.

12

²³ Estimated construction costs for the different generic resource technologies can be found in Section 2.14 of Volume 2.

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**Figure JFH-D-11: \$0/ton ERP and CEP Portfolio
 Infrastructure Investment Potential**

Portfolio	\$0/ton 1	\$0/ton 2	\$0/ton 3	\$0/ton 4	\$0/ton 5	\$0/ton 6	\$0/ton 7	\$0/ton 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Infrastructure Investment Potential (\$M)								
1 Generation 2021-2030 (\$M)	\$ 2,528	\$ 4,226	\$ 3,942	\$ 3,301	\$ 3,540	\$ 4,186	\$ 3,495	\$ 3,558
2 Transmission 2021-2030 (\$M)	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667	\$ 1,667

3 **Q. WHAT ARE THE PROJECTED COSTS OF THE PORTFOLIOS IN FIGURE**
 4 **JFH-D-9?**

5 A. Figure JFH-D-12 below includes several metrics to represent the costs and
 6 benefits of the clean energy actions in \$0/ton 1 through \$0/ton 8, including:

- 7 • The present value of the total annual carbon emissions of each portfolio
8 multiplied by the SCC as established in SB 19-236;
- 9 • The PVRR over the entire 2021-2055 planning period (i.e., the utility costs
10 given they are representative of what is reflected on customer bills); and
- 11 • PVRR over different portions of the planning period to enable Commission to
12 see how cost/benefits are distributed over time.

13 Figure JFH-D-14 contains different combinations of present value of
 14 carbon emissions and PVRR utility costs.

15

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Figure JFH-D-12: \$0/ton ERP and CEP Portfolio Projected Costs

Portfolio	\$0/ton 1	\$0/ton 2	\$0/ton 3	\$0/ton 4	\$0/ton 5	\$0/ton 6	\$0/ton 7	\$0/ton 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1 PVRR Utility Cost 2021-2055 (\$M)	\$ 38,280	\$ 38,875	\$ 38,898	\$ 38,692	\$ 38,791	\$ 38,913	\$ 38,752	\$ 38,898
PVRR Utility Cost Delta vs. \$0/ton 1								
2 2021-2030 (\$M)	\$ -	\$ 221	\$ 153	\$ 189	\$ 193	\$ 163	\$ 160	\$ 248
3 2021-2040 (\$M)	\$ -	\$ 808	\$ 647	\$ 497	\$ 649	\$ 605	\$ 510	\$ 613
4 2021-2055 (\$M)	\$ -	\$ 595	\$ 617	\$ 412	\$ 511	\$ 633	\$ 472	\$ 617
5 NPV CO2 2021-2055 (\$M)	\$ 9,107	\$ 7,051	\$ 7,141	\$ 6,924	\$ 6,971	\$ 7,027	\$ 7,046	\$ 6,758
6 PVRR Utility Cost + NPV CO2 2021-2055 (\$M)	\$ 47,387	\$ 45,926	\$ 46,039	\$ 45,616	\$ 45,762	\$ 45,940	\$ 45,798	\$ 45,656
PVRR Utility Cost + NPV CO2 Delta vs. \$0/ton 1								
7 2021-2030 (\$M)	\$ -	\$ (157)	\$ (133)	\$ (330)	\$ (266)	\$ (210)	\$ (222)	\$ (422)
8 2021-2040 (\$M)	\$ -	\$ (974)	\$ (1,044)	\$ (1,421)	\$ (1,212)	\$ (1,182)	\$ (1,277)	\$ (1,462)
9 2021-2055 (\$M)	\$ -	\$ (1,461)	\$ (1,348)	\$ (1,771)	\$ (1,625)	\$ (1,447)	\$ (1,589)	\$ (1,731)

2 **Q. HOW ARE THE INCREMENTAL COSTS/BENEFITS OF CEP PORTFOLIOS**
 3 **MEASURED IN FIGURE JFH-D-12?**

4 A. As described earlier in my Direct Testimony, the incremental costs and benefits
 5 of the additional clean energy actions in CEP portfolios are determined by
 6 comparing the PVRR Utility costs and NPV CO2 costs of each CEP portfolio to
 7 those of the ERP portfolio. This is the same exercise as that performed above
 8 for the SCC cases.

9 **Q. WHAT ARE THE PROJECTED CUSTOMER RATE IMPACTS OF THESE**
 10 **\$0/TON PORTFOLIOS?**

11 A. The bottom three rows of Figure JFH-D-13 below show projections of the
 12 average annual increase in retail customer rates for three different portions of the
 13 planning period, 2024-2030, 2024-2040, and 2024-2055. Given these again
 14 represent average values for a specific timeframe, in some years the annual rate

1 increase is higher than the average indicated and in other years it is below the
 2 average.

3 **Figure JFH-D-13: \$0/ton ERP and CEP Portfolio Projected Rate Impacts**

Portfolio	\$0/ton 1	\$0/ton 2	\$0/ton 3	\$0/ton 4	\$0/ton 5	\$0/ton 6	\$0/ton 7	\$0/ton 8
Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
Average Annual Rate Impact								
1 2024-2030 (%)	1.8%	2.7%	2.3%	2.2%	2.5%	2.4%	2.1%	2.1%
2 2024-2040 (%)	1.5%	1.4%	1.5%	1.4%	1.4%	1.6%	1.4%	1.5%
3 2024-2055 (%)	1.7%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%

4 Similar to the SCC ERP and CEP portfolios, Figure JFH-D-13 shows
 5 customer impacts at their highest levels between years 2024-2030 when the
 6 clean energy actions to achieve 80 percent clean energy target are being
 7 implemented. The costs for clean energy actions to achieve an 80 percent
 8 emission reduction continue beyond 2030, but generally at lesser amounts
 9 resulting in lower average annual rate impacts. For years 2040-2055, both ERP
 10 and CEP portfolios drive toward the carbon-free by 2050 target, adding more
 11 renewables and an assumption of higher fuel prices due to an ever-increasing
 12 blend of hydrogen into the fuel supply of the gas-fired fleet. These actions to
 13 drive toward the carbon-free by 2050 target result in average annual rate
 14 increases for 2021-2055 up to about 2 percent.

1 **Q. HOW DOES ONE DETERMINE THE TOTAL OR CUMULATIVE PROJECTED**
2 **RATE INCREASE OVER EACH OF THE DIFFERENT TIMEFRAMES IN**
3 **FIGURE JFH-D-13?**

4 A. Total or cumulative rate increases can be estimated by multiplying the average
5 annual rate increase by the number of years in each time frame. For example,
6 the total or cumulative rate increase for the 2024-2030 timeframe for ERP \$0/ton
7 1 would be 10.8 percent, which is equal to 1.8 percent times 6 years. Assuming
8 2024 retail rates were 10¢s/kWh, 2030 rates would be 11.08¢/kWh. Similarly,
9 the cumulative rate increase for the 2024-2055 timeframe for ERP \$0/ton 1 would
10 be 52.7 percent. Assuming 2024 retail rates were 10¢s/kWh, 2055 rates would
11 be 15.27¢/kWh.

12 **Q. HOW DO THE CARBON REDUCTION EFFICIENCY VALUES FOR \$0/TON**
13 **CEP PORTFOLIOS COMPARE WITH ONE ANOTHER?**

14 A. Figure JFH-D-14 below shows how efficient the incremental costs of clean
15 energy actions compare with the incremental carbon reductions achieved
16 through those actions. Lower \$/ton values are better, indicating higher carbon
17 reductions for each incremental dollar spent.

1 **Figure JFH-D-14: \$0/ton ERP and CEP Portfolio CO2 Percent Reduction Efficiency**

	Portfolio	\$0/ton 1	\$0/ton 2	\$0/ton 3	\$0/ton 4	\$0/ton 5	\$0/ton 6	\$0/ton 7	\$0/ton 8
	Resource Need:	ERP	CEP	CEP	CEP	CEP	CEP	CEP	CEP
	Pawnee Action:	Retire EOY 2041	Retire EOY 2028	Retire EOY 2028	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2027	Convert Nat Gas EOY 2024
	Comanche 3 Action:	Retire EOY 2069	Retire EOY 2029	Retire EOY 2039 Red Ops	Convert Nat Gas EOY 2027	Retire EOY 2029	Retire EOY 2039	Retire EOY 2039 Red Ops	Retire EOY 2039 Red Ops
1	2030 CO2 % Reduction	-63%	-81%	-81%	-81%	-81%	-81%	-81%	-81%
2	CO2 Reduction Efficiency (\$/ton)	-	\$ 39	\$ 36	\$ 24	\$ 28	\$ 29	\$ 28	\$ 23
3	PVRR Utility Cost Delta vs. \$0/ton 1 2021-2030 (\$M)	\$ -	\$ 221	\$ 153	\$ 189	\$ 193	\$ 163	\$ 160	\$ 248

1 **VIII. PREFERRED PLAN**

2 **Q. WHAT IS THE PURPOSE OF THIS SECTION OR YOUR TESTIMONY?**

3 A. The purpose of this section of my Direct Testimony is to describe the Company's
4 preferred plan based upon the Phase I generic modeling.

5 **Q. WHAT CONCLUSIONS DOES THE COMPANY DRAW FROM THE ANALYSIS**
6 **OF ERP AND CEP PORTFOLIOS?**

7 A. The Company draws several conclusions from our analyses:

- 8 1. There are multiple paths by which we can reduce emissions by 80 percent or
9 more by 2030 from 2005 levels, all while maintaining an acceptable level of
10 system reliability and affordability for customers.
- 11 2. The previously announced early retirement of 273 MW of coal fired
12 generation at Craig 2 and Hayden²⁴ are key aspects of any plan to achieve 80
13 percent by 2030.
- 14 3. Multiple paired actions can be taken at the two remaining coal-fired units,
15 Pawnee and Comanche 3, to cost-effectively and reliably reduce the emission
16 of carbon from these units.
- 17 4. A relatively balanced mix of new wind and solar resources (distributed and
18 utility scale) will be needed in concert with accelerated coal retirements and
19 paired actions at Pawnee and Comanche 3 to achieve or exceed the 80
20 percent clean energy target by 2030.
- 21
- 22 5. Additional firm dispatchable generation resources are needed that can do the
23 following:
- 24 a. Operate continuously for multiple days to ensure operators can
25 dispatch the level of resources needed to continually serve customer
26 load at all times, particularly during prolonged events in which we
27 experience droughts in wind and solar generation output.
- 28 b. Provide the fast and flexible generation resources needed to reliably
29 manage around the increased level of variability we will see with
30 increasing levels of wind and solar generation on our system.

²⁴ Public Service's ownership share.

1 6. Additional energy storage devices will be needed to provide a host of services
2 that contribute to system reliability and reduced costs to customers through
3 the provision of a variety of benefits including but not limited to: generation
4 capacity credit, various operating reserves, energy arbitrage, and reduction in
5 renewable generation curtailment.

6 **Q. HAS THE COMPANY IDENTIFIED A PREFERRED CEP PORTFOLIO?**

7 A. Yes. The Company's preferred plan is CEP SCC 7. Specifically, the coal actions
8 of the preferred plan include:

- 9 1. Early retirement of Craig 2 in 2028 and Hayden 1 in 2028 and Hayden
10 2 in 2027;
- 11 2. Conversion of Pawnee to burn natural gas by 2028; and
- 12 3. Reducing generation from Comanche 3 to a level representative of a
13 33 percent annual capacity factor beginning in 2030 and early retiring
14 the unit in 2040.

15 Coupled with these coal actions are indicative levels of generic wind,
16 solar, storage, and firm and flexible dispatchable resources of approximately
17 2,300 MW, 1,600 MW, 400 MW, and 1,300 MW respectively. The actual level
18 and composition of these and other resource technologies in the preferred plan
19 will be determined through the Phase II competitive solicitation and bid
20 evaluation process.

21 **Q. WHAT FACTORS LED TO THE SELECTION OF CEP PORTFOLIO SCC 7 AS**
22 **THE COMPANY'S PREFERRED PLAN?**

23 A. In general, the primary factors considered: (1) the level of projected carbon
24 reductions; (2) the additional costs for achieving those reductions; and (3) the
25 community and workforce transition impacts of clean energy actions. While
26 maintaining system reliability is of paramount importance to the Company, we

1 believe that all CEP portfolios were built to a comparable and acceptable level of
2 reliability and therefore we did not see reliability as a distinguishing characteristic
3 between portfolios. Similarly, given that the indicative levels of wind and solar
4 additions in each portfolio are in large part directly reflected in the projected
5 carbon emission reductions of each portfolio, we did not see the levels of wind
6 and solar adds as a distinguishing characteristic of portfolios, separate from
7 projected carbon emission reductions.

8 **Q. HOW DID THE LEVEL OF EMISSION REDUCTIONS INFORM SELECTION OF**
9 **SCC 7?**

10 A. As a threshold matter, given that CEP portfolios developed using the SCC show
11 higher CO₂ emission reductions than portfolios developed using \$0/ton for
12 carbon, the Company focused on the results of the modeling optimizations that
13 used the SCC in selecting a preferred portfolio.

14 As shown in Figure JFH-D-3, each of the seven CEP portfolios developed
15 using SCC exceed 80 percent emission reductions, with SCC 2 and 5 showing
16 the highest reductions at 88 percent, SCC 3, 4, 7, 8 showing between 84 to 86
17 percent, and SCC 6 showing the lowest reductions at 81 percent. From this
18 perspective, SCC 7 provides a level of CO₂ emission reductions toward the
19 middle of the range but well beyond that contemplated in the emission reduction
20 target of SB 19-236.

1 **Q. HOW DID CUSTOMER COSTS INFORM SELECTION OF SCC 7?**

2 A. Customer costs were considered from two general perspectives: (1) average
3 annual rate impacts: and (2) the efficiency of the dollars spent on clean energy
4 actions at reducing CO₂ emissions.

5 As shown in Figure JFH-D-7, SCC 6, 7, 8 show the lowest 2024-2030
6 annual average rate impacts of 2.4 percent, 2.6 percent, and 2.5 percent,
7 respectively. SCC 2, 3, 4, 5 show higher impacts of 3.1 percent, 2.8 percent, 2.8
8 percent, and 2.9 percent, respectively. From this perspective, SCC 7 shows
9 increased costs to customers at the lower end of the range. The average annual
10 rate impacts of all CEP portfolios for years 2024-2040 and years 2024-2055
11 converge to 1.6 percent; as a result, we did not see rate impacts for these longer
12 timeframes as a distinguishing characteristic of portfolios from a decision-making
13 perspective.

14 **Q. HOW DID THE EFFICIENCY OF THE DOLLARS SPENT ON CLEAN ENERGY**
15 **ACTIONS AT REDUCING CO₂ EMISSIONS INFORM SELECTION OF SCC 7?**

16 A. As shown in Figure JFH-D-8, SCC 8 shows a CO₂ reduction efficiency at \$28/ton,
17 due mostly to the way the metric favors CO₂ reductions that occur earlier versus
18 those that occur later.²⁵ SCC 4, 5, 6, 7 show CO₂ reduction efficiencies between
19 \$34/ton and \$38/ton and SCC 2 and 3 show \$46/ton and \$48/ton, respectively.
20 As discussed earlier in my Direct Testimony, a lower \$/ton value is better in that it
21 provides a general indication of higher CO₂ reductions for each incremental

1 dollar spent. From this perspective, SCC 7 shows a CO₂ reduction efficiency at
2 the middle of the range.

3 **Q. HOW DID COMMUNITY AND WORKFORCE TRANSITION CONSIDERATIONS**
4 **INFORM SELECTION OF SCC 7?**

5 A. The Company placed considerable importance on minimizing the impacts of the
6 preferred plan coal actions on local communities and our workforce. SCC 7
7 minimizes these impacts by continuing to operate the Pawnee and Comanche 3
8 units to 2041 and 2039, respectively. The Pawnee plant located in Brush,
9 Colorado will be converted to burn natural gas and operated to year 2041, which
10 is the current retirement date of the unit. The Comanche 3 unit will continue to
11 operate on coal at reduced levels from 2030-2039 and then will be retired. The
12 Company's workforce transition and community assistance plans are discussed
13 in more detail by Company witnesses Ms. Jackson, Ms. Holly L. Stanton, and
14 Ms. Hollie J. Velasquez Horvath.

15 **Q. WHAT OTHER CHARACTERISTICS OF SCC 7 ARE IMPORTANT TO**
16 **CONSIDER?**

17 A. In addition to the characteristics described above, we believe another potential
18 benefit of SCC 7 is that it shows a requirement for considerably less new firm
19 dispatchable generation resources as compared to other SCC portfolios. More
20 specifically, the 1,276 MW level of new firm dispatchable resources in SCC 7 is

²⁵ As a result of using the present value of CO₂ reductions in this calculation, SCC 8 shows a higher reduction efficiency than other CEP portfolios even though some of those other portfolios result in overall higher carbon emission reductions by 2030.

1 between approximately 230 – 1,100 MW less than that included in all other SCC
2 portfolios, with the exception of SCC 8.

3 **Q. WHAT ARE SOME OF THE REASONS THE COMPANY LANDED ON SCC7**
4 **WITH COMANCHE 3 ON REDUCED OPERATIONS?**

5 A. SCC 7 is a solid portfolio from an emission reduction standpoint, and it falls in the
6 middle or towards the upper bounds of the ranges across the SCC portfolios.
7 The preferred plan is projected to result in approximately an 85 percent emission
8 reduction from 2005 levels by 2030—well above the 80 percent clean energy
9 target of SB 19-236 and adding to the State of Colorado’s overall emission
10 reductions. There are three key reasons support why we landed on this
11 approach for Comanche 3.

12 **Q. WHAT IS THE FIRST REASON?**

13 A. A good comparison point for SCC 7 is against SCC 6 because SCC 6 has the
14 same action at Pawnee (conversion to natural gas at the end of 2027) while
15 keeping Comanche 3 on through 2040 *without reduced operations*. The SCC 6
16 scenario achieves only 81 percent emission reductions and thus hi-lights the
17 emission reduction value of the reduced Comanche 3 operations post-2029.
18 Moreover, the SCC 6 portfolio results in (1) more firm dispatchable acquisitions
19 (1,505 MW) as compared to SCC 7 (1,276 MW), (2) less wind (1,850 MW) than
20 SCC 7 (2,300 MW), and (3) less utility-scale solar (1,250 MW) than SCC 7 (1,550
21 MW), too.

1 **Q. WHAT IS THE SECOND REASON?**

2 A. The “dual 2030 retirement scenario,” *i.e.*, where both Pawnee and Comanche 3
3 are retired at end of year 2029, is SCC2. This scenario achieves an 88 percent
4 emission reduction by 2030; however, it is important to go a layer deeper and
5 look at the projected resource additions under this scenario as well as the added
6 costs. The dual retirement scenario results in the acquisition of 2,350 MW of
7 wind, 1,550 MW of solar, and 450 MW of storage, only 50 MW more wind and 50
8 MW more storage, and the same amount of solar, as compared to our SCC 7
9 preferred plan but at an added utility cost of \$65 million, \$472 million, and \$276
10 million over the 2021-2030, 2021-2040, and 2021-2055 timeframes, respectively.
11 Another key difference is in the addition of firm dispatchable resources, as the
12 dual retirement scenario adds approximately 2,300 MW of these resources while
13 the preferred plan adds only 1,300 MW. With approximately 1,400 MW of gas
14 resources having expiring PPAs or retiring in the RAP, the net result is that the
15 dual retirement scenario requires substantial incremental firm dispatchable
16 resources, likely to be met in large part by gas additions, over and above that of
17 our preferred plan. This goes to the option value discussion in the Direct
18 Testimony of Ms. Jackson and why long-term thinking towards a carbon-free
19 future, rather than a shorter-term approach, is imperative in this proceeding.

20 **Q. WHAT IS THE THIRD REASON?**

21 A. The third reason is that Comanche 3 continues to get a full accredited capacity
22 credit under a reduced operations scenario, which is a benefit to the system and
23 a benefit associated with the portfolio. Comanche 3 operation is limited but it is

1 still a generator the Company can rely on to maintain system reliability if system
2 conditions and circumstances warrant.

3 **Q. BUILDING ON YOUR SECOND REASON ABOVE, WHY DOES THE**
4 **COMPANY BELIEVE THAT REQUIRING LESS FIRM DISPATCHABLE**
5 **RESOURCES IS A POTENTIAL BENEFIT TO SCC 7?**

6 A. As a general matter, the current generation technology probably best suited to
7 fulfill the role of firm dispatchable resources that can be started whenever
8 needed and operated continuously for several days, are gas-fired combustion
9 turbines or CTs. Certain parties to the Company's last ERP openly opposed the
10 inclusion of two gas fired CTs that were included as part of the Colorado Energy
11 Plan. As we understand, their opposition centered around that these CTs would
12 burn natural gas, which is a fossil fuel. It is our expectation that these or other
13 parties to this 2021 ERP will take a similar position and oppose the acquisition of
14 new gas-fired CTs in Phase II. In this regard, the Company believes that the
15 lower levels of firm dispatchable resources in SCC 7 would be viewed by these
16 same parties as a plus.

17 **Q. IS CURRENT COMBUSTION TURBINE (CT) TECHNOLOGY LIMITED TO**
18 **BURNING ONLY NATURAL GAS?**

19 A. No. We have contacted GE, Siemens, and MHI and confirmed that each supplier
20 currently has CT units available that are capable of burning 30 percent hydrogen
21 (by volume). Furthermore, each of these suppliers indicated that their goal is to
22 have CT units capable of burning 100 percent hydrogen available to the market
23 by 2030.

1 **Q. DOES THE COMPANY INTEND TO REQUEST IN THE PHASE II BIDDING**
2 **PROCESS A HYDROGEN BLEND CAPABILITY OPTION BE PROVIDED**
3 **WITH BIDS PROPOSING THE CONSTRUCTION OF NEW CTS OR NEW**
4 **RECIPROCATING ENGINES?**

5 A. Yes. We are proposing to include language in the RFP document that
6 encourages bids proposing a new CT facility or new reciprocating engine facility
7 to provide an option for the facility to be capable of burning, at a minimum, 30
8 percent hydrogen (by volume), over the entire operating range of the unit (i.e.,
9 from minimum MW loading to maximum MW loading) while meeting emission
10 permit requirements. This alternative fuel capability will allow the Company to
11 transition toward our goal of a carbon-free future by 2050.

1 **IX. ERP AND CEP PORTFOLIO SENSITIVITY ANALYSIS**

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

3 A. The purpose of this section of my Direct Testimony is to discuss the various
4 sensitivities performed by the Company on the portfolios developed for this
5 Phase I proceeding.

6 **Q. PLEASE DESCRIBE THE SENSITIVITY ANALYSES THAT WERE**
7 **PERFORMED ON ERP AND CEP PORTFOLIOS.**

8 A. In addition to the evaluation of ERP and CEP portfolios under base assumptions,
9 portfolios were further analyzed through sensitivity analyses. These sensitivity
10 analyses involve changing a single key input assumption and assessing how that
11 change impacts a portfolio's carbon cost (i.e., repricing sensitivity) or the
12 composition of resources added within the portfolio (i.e., reoptimized sensitivity).
13 The primary purpose of sensitivity analyses is to test the robustness of the
14 Company's selection of SCC 7 as our preferred plan under different futures. A
15 detailed presentation of the sensitivity analyses performed is provided in Section
16 2.13 of Volume 2.

17 **Q. WHAT IS THE DIFFERENCE BETWEEN A REPRICING SENSITIVITY AND A**
18 **REOPTIMIZED SENSITIVITY?**

19 A. The difference between the two types of analyses is whether the capacity
20 expansion plan of the portfolio (i.e., the new resources that are added) is re-
21 optimized. Some sensitivities, such as change in fuel prices, do not require that
22 a new optimized expansion plan be developed in order to assess the impact of

1 the changed assumption. These types of sensitivities are referred to as repricing
2 sensitivities. In contrast, there are certain sensitivities, such as changes in load,
3 where it is necessary to develop a new optimized expansion plan in order for a
4 meaningful comparison of the sensitivity results with the base assumption
5 results. In these sensitivity analyses, the model is given the flexibility to select a
6 different mix of generic resources from those selected in the optimization
7 performed using base assumptions. These types of sensitivities are referred to
8 as reoptimized sensitivities.

9 **Q. PLEASE DESCRIBE THE REPRICING SENSITIVITIES PERFORMED ON ERP**
10 **AND CEP PORTFOLIOS.**

11 A. Repricing sensitivities were performed on each ERP and CEP portfolio under the
12 following assumptions:

13 High Gas Prices: Increase natural gas prices by using twice the annual
14 year-over-year growth rate of base gas price forecast.

15 Low Gas Prices: Reduce natural gas prices by using one-half the annual
16 year-over-year growth rate of base gas price forecast.

17 **Q. PLEASE DESCRIBE THE REOPTIMIZED SENSITIVITIES PERFORMED ON**
18 **ERP AND CEP PORTFOLIOS.**

19 A. Reoptimized sensitivities were performed on each ERP and CEP portfolio under
20 the following assumptions:

21 High Load: Widespread electrification consistent with the Greenhouse
22 Gas Emission Reduction Roadmap developed by State of Colorado
23 agencies and described in more detail in the Direct Testimony of
24 Company witness Ms. Jackson.

25 Low Sales: Widespread adoption of distributed energy resources.

1 Expanded Market Access: Double the MW import and export capacity
2 within the modeling.

3 Sunk Transmission Upgrade Cost: Assumes transmission network
4 upgrade costs are sunk.

5 No New Gas Resources: Assumes no new gas-fired generation are
6 added to the system.

7 Lower Hydrogen Costs: Reduce the hydrogen price assumption from
8 \$20/MMBTU to \$10/MMBTU for the 2041-2055 period of the modeling.
9 This is the period over which hydrogen blending occurs at an increasing
10 rate of 10 percent each year, reaching 100 percent by 2050, for all gas-
11 fired resources.

12 High and low load sensitivities were run for all ERP and CEP portfolios 1-8
13 for both SCC and \$0/ton. Expanded Market Access, Sunk Transmission Upgrade
14 Cost, No New Gas Resources, and Lower Hydrogen Cost sensitivities were run
15 for ERP portfolio 1 and CEP portfolios 2,4,7 for the assumption that CO2
16 emissions are priced at the SCC.

17 **Q. WHAT WERE THE RESULTS OF THESE ANALYSES?**

18 A. A detailed accounting of the numeric results of all sensitivity analyses are
19 provided in ERP Volume 2, Section 2.13. To the extent that parties desire to drill
20 down into the results of the analysis to better understand how a particular
21 portfolio cost or benefit was affected in a specific sensitivity, that information is
22 available in ERP Volume 2. However, to walk through in testimony the impacts
23 of the eight sensitivity analyses on the various aspects of each plan would not be
24 particularly instructive in my opinion. Accordingly, I instead provide higher-level
25 observations as to how the sensitivity results serve to buttress the Company's
26 selection of SCC 7 as the preferred plan.

1 **Q. CAN YOU DESCRIBE THE GENERAL PROCESS BY WHICH YOU**
2 **ASSESSED THE RESULTS OF THE SENSITIVITIES?**

3 A. Yes. I assessed how the sensitivity analyses impacted each portfolio by applying
4 a colored heat mapping concept to the analyses results. The colored heat
5 mapping illustrates at a high level how the different portfolios compare or rank
6 relative to one another for a particular portfolio characteristic (e.g., CO₂
7 reductions, PVRR utility costs, etc.) under a particular sensitivity. We applied a
8 three-tiered color scale in which green represents the highest rank, yellow a
9 middle rank, and red the lowest rank. One of the limitations of this heat mapping
10 approach is that it does not provide information as to whether the difference
11 between a green, yellow or red ranking for a particular plan characteristic is a
12 material difference. For example, a \$10 million difference in the 2021-2055
13 PVRRs between portfolios could result in one portfolio ranking green and another
14 red. However, recognizing that the total 2021-2055 PVRR of portfolios is in the
15 \$40 billion range, a \$10 million difference between plans in this instance is
16 immaterial. Nevertheless, the materiality of different color rankings for each plan
17 characteristic is readily available within the numeric values provided in the
18 sensitivity results in ERP Volume 2.

19 **Q. WHAT OBSERVATIONS AND CONCLUSIONS DO YOU DRAW FROM THE**
20 **SENSITIVITY ANALYSIS RESULTS?**

21 A That SCC 7 is a robust plan that can be expected to deliver on the CO₂ emission
22 reduction targets of SB 19-236 and do so in an affordable and reliable manner for

1 customers. I base this conclusion on the following observations from the
2 sensitivity results:

- 3 • From a carbon reduction perspective, SCC 7 shows no erosion of CO₂
4 reductions from the approximately 85 percent level projected under
5 base assumptions. In fact, in four of the eight sensitivities, SCC 7 CO₂
6 reductions were shown to improve by increasing up to 89 percent.
- 7 • From a customer cost perspective, SCC 7 consistently ranks between
8 the middle and the top relative to other portfolios across all eight
9 sensitivities. This is evident by the green and yellow rankings of SCC
10 7 for PVRR Utility Costs Deltas versus the SCC 1 reference case, as
11 well as in Average Annual Rate Impacts.
- 12 • From a CO₂ reduction efficiency perspective, SCC 7 ranks between the
13 middle and the top relative to other portfolios in seven of the eight
14 sensitivities. This is evident by the green and yellow rankings of SCC
15 7 for CO₂ Reduction Efficiency (\$/ton).

16 **Q. HOW DOES SCC 7 RANK FROM A SYSTEM RELIABILITY PERSPECTIVE?**

17 A As discussed earlier in my testimony, we believe that all CEP portfolios were built
18 to a comparable and acceptable level of reliability; therefore, we did not see
19 reliability as a distinguishing characteristic between portfolios.

20

1 These modeling inputs and assumptions are outlined in Section 2.14 of ERP
2 Volume 2 and described in the Direct Testimony of Mr. Landrum. We will also
3 follow the approach used in prior ERP cycles, where we make the final modeling
4 inputs and assumptions available through a compliance filing after the Phase I
5 decision but prior to the issuance of the RFPs that will commence the Phase II
6 competitive solicitation process.

7 **Q. ARE THERE ANY SPECIFIC RELIABILITY REQUIREMENTS FOR THE**
8 **PHASE II COMPETITIVE SOLICITATION?**

9 A. Yes. These are explained in more detail in the Direct Testimony of Mr. Welch.
10 As an overview, the Company proposes the following requirements be met in the
11 evaluation and selection of Phase II bids, specifically:

- 12 *1. A requirement that all proposed new or repowered/refurbished wind*
13 *resources must be equipped with the appropriate cold-weather packages*
14 *that will allow the turbines to reliably operate down to temperatures of*
15 *negative 30 degrees Celsius or negative 22 degrees Fahrenheit.*
- 16 *2. A requirement that all bids offering new or existing dispatchable resources*
17 *provide a description detailing the units cold-weather/winterization*
18 *processes and packages*
- 19 *3. A requirement that all bids offering new or existing gas-fired resources*
20 *provide an option for the storage of onsite fuel such as fuel-oil, of sufficient*
21 *quantity to power the unit at maximum unit output for 3 consecutive days*

22 **Q. WILL THE COMPANY BE REQUESTING BEST VALUE EMPLOYMENT**
23 **METRICS FROM BIDDERS CONSISTENT WITH § 40-2-129, C.R.S.?**

24 A. Yes. This is explained by Company witness Ms. Jackson, but we will be
25 including and enforcing the BVEM requirements in our Phase II bid evaluation.
26 While the Commission has not finalized BVEM rules, the Company worked

1 extensively with labor interests to develop more detailed and robust BVEM for
2 competitive solicitations. In keeping with what we worked on, the Company
3 provides the guidelines below as part of the RFPs in Volume III:

4 *Best Value Employment Metrics - Information Guidelines*

5 (a) *The availability of training programs, including training*
6 *through apprenticeship programs registered with the United*
7 *States Department of Labor, Office of Apprenticeship and*
8 *Training. The utility or bidder shall provide, for example and*
9 *as applicable, the following information for each craft the*
10 *utility anticipates will work on the project:*

- 11 (I) *availability of training programs;*
12 (II) *the names of specific training programs available;*
13 (III) *the curriculum of the specific training programs;*
14 (IV) *the cost of worker training;*
15 (V) *the duration of the training programs;*
16 (VI) *the total number of hours of on-the-job training required;*
17 (VII) *the total number of classroom hours required;*
18 (VIII) *the licenses and certifications obtained, if any;*
19 (IX) *a copy of training program standards for each training*
20 *program; and*
21 (X) *a statement whether the training programs are United*
22 *States Department of Labor registered apprenticeship*
23 *programs and are accredited to award college credits.*

24 (b) *The employment of Colorado workers as compared to*
25 *importation of out-of-state workers. The utility or bidder shall*
26 *provide, for example and as applicable, the following*
27 *information for each craft the utility anticipates will work on*
28 *the project:*

- 29 (I) *estimated number of workers by job classification;*
30 (II) *estimated length of time of service, including total man*
31 *hours, by job classification;*
32 (III) *percentage of Colorado workers by job classification;*
33 *and*
34 (IV) *percentage of project man hours earned by Colorado*
35 *workers by job classification.*

1 (c) *Long-term career opportunities. The utility or bidder shall*
2 *provide, for example and as applicable, the following*
3 *information for each craft the utility anticipates will work on*
4 *the project: job classifications, licenses, certifications and*
5 *skills that will be applied and the long-term career*
6 *opportunities for each job classification; and*

7 (d) *Industry-standard wages, health care, and pension benefits.*
8 *The utility or bidder shall provide, for example and as*
9 *applicable, the following information for each craft the utility*
10 *anticipates will work on the project:*

11 *(I) range of wages by job classification;*

12 *(II) healthcare benefits by job classification;*

13 *(III) pension benefits by job classification;*

14 *(IV) prevailing wages and fringe benefits (healthcare*
15 *benefits, pension benefits and other compensation) based*
16 *on industry standards and the current Colorado labor*
17 *agreements by job classification; and*

18 *(V) wages and fringe benefits (healthcare benefits, pension*
19 *benefits and other compensation) by job classification.*

20

1 **XI. CONCLUSION**

2 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

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

6 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

7 A. Yes.

James F. Hill

Statement of Qualifications

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