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

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF AN ECONOMIC DEVELOPMENT RATE PROPOSAL PURSUANT TO COLORADO HB 18-1271	**)**	**PROCEEDING NO. 20A-XXXXE**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN W. WISHART</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

August 21, 2020

**BEFORE THE PUBLIC UTILITIES COMMISSION
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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
Black Hills EDR Proceeding	Application of Black Hills Colorado Electric LLC for the Approval of its Economic Development Rate Tariff in Proceeding No. 18A-0791E
CACJA	Clean Air-Clean Jobs Act
CEPA	Colorado Energy Plan Adjustment
Commission	Colorado Public Utilities Commission
CT	Combustion Turbine
DSMCA	Demand-Side Management Cost Adjustment
ECA	Electric Commodity Adjustment
EDR	Economic Development Rate
G&T	Generation and Transmission
GRSA	General Rate Schedule Adjustment
GRSA-E	General Rate Schedule Adjustment – Energy
HB 18-1271	House Bill 18-1271
kWh	Kilowatt Hour
MW	Megawatt
PCCA	Purchased Capacity Cost Adjustment
PG	Primary General
Public Service or Company	Public Service Company of Colorado
QF	Qualifying Facilities
RESA	Renewable Energy Standard Adjustment

Acronym/Defined Term	**Meaning**
S&F	Service and Facilities
Staff	Commission Trial Staff
TCA	Transmission Cost Adjustment
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven W. Wishart. My business address is 1800 Larimer, Suite 1100, Denver, Colorado 80202.

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

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

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Director of Pricing and Planning, I am responsible for financial and policy analyses associated with the Company's electric, natural gas, and steam rates, in addition to the regular administration of the Company's electric, natural gas, and steam tariffs. My duties include providing quantitative analyses, cost allocation and rate design, and policy support on various state regulatory issues. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The primary purpose of my Direct Testimony is to present the Company's Economic Development Rate ("EDR") proposal, which, if approved, would enable us to enter into Standard EDR Contracts with qualifying new customers with load between three and 20 megawatts ("MW"). I provide supporting analysis that demonstrates the Company's proposed base rate discount and non-base rate adjustments result in monthly charges that are above the marginal cost of service and do not result in subsidization by other customers, consistent with House Bill ("HB") 18-1271. The Company has estimated the marginal costs of service for a typical Commercial & Industrial ("C&I") customer taking service under our proposed EDR would be about 3.5 cents per kWh ("Kilowatt Hour"). The Company's proposed EDR discount would result in qualifying customers paying about 4.9 cents per kWh over a 10-year contract term. I also lay out the Company's proposed process by which the Colorado Public Utilities Commission

("Commission") can review and approve Non-Standard EDR Contracts for customers adding or expanding more than 20 MW of load.

In Section II, I provide an overview of the Company's proposed EDR tariff, which includes a standardized discount to base rate charges for Standard EDR Contracts, which are EDR contracts with qualifying customers adding load between three and 20 MW that take the EDR discounts provided in a Commission-approved EDR tariff. Under House Bill ("HB") 18-1271, these Standard EDR Contracts do not require Commission approval. The proposed base rate discounts gradually decline over a 10-year term, providing a smooth transition to standard rates at the end of the customer's EDR contract.

In Sections III and IV, I discuss how the Company's proposal is consistent with the State's enabling legislation, and how it addresses other issues identified by the Commission in Proceeding No. 18A-0791E, Black Hills Colorado Electric LLC's Application for Approval of an Economic Development Rate Tariff (the "Black Hills EDR Proceeding").

In Sections V and VI, I review the Company's proposed modifications to its Distribution Extension Policy and provide greater detail regarding the EDR tariff itself. In doing so, I explain how customers will qualify for the EDR tariff, all charges EDR customers will be subject to, and how those charges may change over time. I conclude this section by providing an illustrative estimate of how an EDR customer's annual bills may compare under the EDR tariff to standard rates.

In Section VII, I present the Company's definitions of marginal costs and the analysis the Company has conducted to quantify those costs. The Company proposes to calculate marginal costs consistent with the Commission Trial Staff's ("Staff") recommendation in the Black Hills EDR Proceeding, including the marginal cost of generation, transmission, distribution, energy, customer specific facilities, hedging, corporate services, taxes, and fees. The Company's analysis demonstrates that the marginal cost of service for an EDR customer is expected to be well below the charges to EDR customers, ensuring that the Company's proposal is consistent with C.R.S. § 40-3-104.3.

In Section VIII, I describe the various regulatory processes that will be created or modified as a result of the Company's EDR proposal. I first explain the proposed process for qualifying customers to receive the EDR discount and present Public Service's proposal to provide the Commission the opportunity to review qualifying EDR customers' eligibility to receive an EDR discount for Standard EDR Contracts. Next, I present the Company's proposal for annual reporting on EDR activity that will allow the Commission to track total sales to EDR customers. I also discuss the recommended treatment of EDR costs and revenues in the context of a rate case proceeding, which will allow all customers to benefit from incremental EDR revenue. I conclude this section by describing how the Company proposes to update its Electric Commodity Adjustment ("ECA") and Demand-Side Management Cost Adjustment ("DSMCA") tariffs for EDR customers.

In Section IX, I explain how existing customers will benefit from new EDR customer load being added to Public Service's system and address the revenue sharing proposals that were part of the Black Hills EDR Proceeding in the context of this proceeding. Public Service opposes the creation of any artificial revenue sharing mechanism that penalizes the Company for attracting new business and jobs to Colorado. I discuss that there is no precedent for administratively taking new revenue streams away from the Company and that doing so would be a negative policy decision that undermines the legislative intent of C.R.S. § 40-3-104.3.

In Section X, I present Public Service's request to establish an expedited process for the Commission to address applications for Commission approval of Non-Standard EDR Contracts, which require Commission approval under HB 18-1271 and include all EDR contracts with qualifying customers adding more than 20 MW of load, and EDR contracts with qualifying customers adding load between three and 20 MW that that provide for a discount other than the discount(s) provided in a Commission-approved EDR tariff. In addition to addressing Non-Standard EDR Contracts, this expedited process would also apply to requests to expand voluntary renewable programs to accommodate EDR customers pursuant to C.R.S. § 40-3-104.3(6)(d).

Finally in Section XI, I support the Company's request to defer the costs of making this filing and supporting this proceeding, for future cost recovery.

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

A. Yes, I am sponsoring the following attachments, which were prepared by me or under my direct supervision:

Attachment SWW-1	Economic Development Rate Tariff
Attachment SWW-2	Redline Versions of Distribution Line Extension, ECA and DSMCA Tariffs
Attachment SWW-3	Clean Versions of Distribution Line Extension, ECA and DSMCA Tariffs
Attachment SWW-4	Transmission and Distribution Study
Attachment SWW-5	Marginal Cost Analysis
Attachment SWW-6	Long Term Marginal Cost of Distribution

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. I recommend that the Commission:

1) Find that the terms and conditions set forth in the Company's illustrative EDR tariff, provided as Attachment SWW-1, are reasonable, in the public interest, and consistent with C.R.S. § 40-3-104.3. In doing so, I recommend that the Commission find that the Company's proposed EDR discounts are reasonable and appropriate, as they result in charges that are above the marginal cost of service and the rates assessed to other customers will not subsidize the cost of providing service to EDR customers.
2) Authorize the Company's proposed modifications to its Distribution Extension Policy tariff, COLO. PUC No. 8 Electric, Sheet No. R207 and

R227, as embodied in Attachments SWW-2 (redline) and SWW-3 (clean).

3) Authorize the Company's proposed modifications to the ECA and DSMCA tariffs, COLO. PUC No. 8 Electric, Sheet No. 143 and 140, as embodied in Attachments SWW-2 (redline) and SWW-3 (clean).[1]

4) Authorize the Company to file a compliance advice letter within 20 days of the effective date of a final order in this proceeding, but on not less than two business days' notice, that includes all new tariffs and tariff modifications that are authorized as part of this proceeding, including the EDR tariff itself, and modifications to Public Service's Distribution Extension Policy, ECA, and DSMCA tariffs to reflect all terms and conditions that are authorized as a result of this proceeding.

5) Approve the Company's proposal to provide the Commission the opportunity to review qualifying EDR customers' eligibility to receive an EDR discount for Standard EDR Contracts pursuant to C.R.S. § 40-3-104.3 (7)(a)(I)(B).

6) Approve Public Service's proposal concerning annual reporting of EDR sales.

7) Approve Public Service's proposed treatment of EDR costs and revenues in ratemaking proceedings.

8) Approve the Company's proposed expedited procedural process for the Commission to address applications for Commission approval of Non-Standard EDR Contracts and for requested expansions of voluntary renewable programs to accommodate EDR customers pursuant to C.R.S. § 40-3-104.3(6)(d).

[1] Also included in Attachments SWW-2 (redline) and SWW-3 (clean) are related changes to the Table of Contents and Index to accommodate the EDR tariff changes. Additionally, the rate sheets for the proposed ECA and DSMCA tariff revisions, Sheet 140 and Sheet 143A in SWW-2 and SWW-3, include estimated values that will be updated in the compliance advice letter referenced above.

9) Authorize Public Service to track, record, and defer all costs incurred to prepare and prosecute this Application in a non-interest bearing regulatory asset account until they are presented for review and recovery in a future cost recovery proceeding.

Further, I recommend the Commission not require any revenue sharing mechanism associated with EDR customers or the keeping of separate books and records for EDR customers. Incremental revenues from EDR customers will help lower rates for all customers and the imposition of a revenue sharing mechanism would diminish the incentive for the Company to pursue EDR customers. A revenue sharing mechanism would also be inconsistent with past treatment of incremental sales revenue. Maintaining a separate set of books and records for EDR customers would create significant administrative burdens and complexities for Public Service and is unnecessary to ensure compliance with C.R.S. § 40-3-104.3(6) given the Company's comprehensive approach to ensuring that EDR customers will cover the full extent of the Company's incremental cost to serve them.

II. OVERVIEW OF THE COMPANY'S EDR PROPOSAL

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

A. In this section of my Direct Testimony, I provide an overview of the Company's EDR proposal. I introduce the EDR terms and conditions and discount structure, proposed changes to the Company's Distribution Extension Policy, EDR reporting, how customers will qualify for the EDR, and treatment of EDR revenues in rate case proceedings. I discuss each of these topics in more detail in subsequent sections of testimony.

Q. PLEASE SUMMARIZE PUBLIC SERVICE'S EDR PROPOSAL.

A. Public Service is proposing to implement an EDR consistent with C.R.S. § 40-3-104.3, which allows the Company to offer lower rates for qualifying customers. The overarching purpose of C.R.S. § 40-3-104.3 is to stimulate economic development by encouraging companies to locate or expand their business operations in Colorado. The Company's illustrative EDR tariff is included as Attachment SWW-1. The Company's proposal seeks to strike a balance between regulatory efficiency and compliance with statutory requirements, by proposing base rate discounts that are substantially above the forecasted marginal cost to serve qualifying EDR customers. This conservative approach ensures that the tariff complies with the requirements of C.R.S. § 40-3-104.3 and provides prospective EDR customers with regulatory certainty and efficiency in navigating any Commission approvals that may be needed to move forward. Our proposal in this proceeding includes:

- an EDR that offers an initial base rate discount of 40 percent for a 10-year contract that declines over the term of the contract;
- modifications to the Company's current Distribution Extension Policy to remove the construction allowance for EDR customers;
- the creation of a modified ECA charge ("EDR ECA Factor") that would be applied to EDR customers through the ECA;
- the creation of a full DSMCA charge that would be charged to EDR customers;
- a proposal for annual reporting on EDR activity;
- recommended treatment of EDR costs and revenues in rate case proceedings;
- a process for determining how customers qualify for EDR rates and a proposal to provide the Commission the opportunity to review qualifying EDR customers' eligibility to receive an EDR discount for Standard EDR Contracts; and
- an expedited procedural framework to address Non-Standard EDR Contracts and requests to expand existing voluntary renewable programs to accommodate EDR customers.

Although Public Service is not seeking approval to effectuate its proposed tariff or tariff changes in this Application proceeding, Attachments SWW-1, SWW-2 (redline), and SWW-3 (clean) reflect the tariff changes the Company is proposing in order to implement its EDR. These modifications would be implemented through a separate compliance advice letter filing if the Commission authorizes the Company's proposals in this proceeding.[2] As reflected in our Application, to the extent the Commission modifies Public Service's proposal in a

[2] Public Service requests that in its final order, the Commission authorize the Company to file a compliance advice letter within 20 days of the effective date of its final order, but on not less than two business days' notice, to effectuate its proposed tariff changes reflecting all terms and conditions that are approved as a result of this proceeding.

manner Public Service finds unacceptable, Public Service respectfully requests the final order reflect that the Company maintains discretion as to whether it implements the EDR proposals and related tariff modifications that are authorized as a result of this Application proceeding.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S ILLUSTRATIVE EDR TARIFF.

A. Our Illustrative EDR tariff, provided as Attachment SWW-1, is a modification of other C&I tariffs. Customers would take service under one of the Company's existing C&I tariffs, either Secondary General Service ("SG"), Primary General Service ("PG"), or Transmission General Service ("TG"). The EDR would then provide a base rate discount that is applied to the Company's standard rates and modifies the non-base rate adjustments paid by EDR customers. The first part of the illustrative EDR tariff consists of an applicability and availability section that specifies which customers qualify for the EDR tariff and how they would qualify. The tariff then lays out the base rate discount and non-base rate adjustments that will be paid by EDR customers. The last section contains rules and regulations specific to the EDR tariff.

Q. WHAT ARE THE BASE RATE DISCOUNTS SPECIFIED IN THE EDR TARIFF?

A. The tariff would specify an initial 40 percent discount on Generation and Transmission ("G&T") demand charges, distribution demand charges (if applicable), and volumetric energy charges. The discounts are not applied to a customer's monthly Service and Facilities ("S&F") charge. Table SWW-D-1 below lists the base rate discounts that the Company is proposing based on a 10-year contract.

Table SWW-D-1 – EDR Base Rate Discounts

Time Period	Base Rate Discount
Years 1-3	40%
Years 4-5	30%
Years 6-7	20%
Years 8-10	10%

Q. WHAT IF AN EDR CUSTOMER PREFERS A CONTRACT THAT IS SHORTER THAN THE STATUTORY MAXIMUM OF 10 YEARS?

A. The EDR would include different discount structures for terms shorter than 10 years. As Table SWW-D-2 below demonstrates, as contract lengths are shortened the largest base rate discounts are eliminated first. This creates incentives for customers to commit to remaining a Public Service customer for the maximum term possible.

Table SWW-D-2

		Contract Term									
		1 Year	2 Year	3 Year	4 Year	5 Year	6 Year	7 Year	8 Year	9 Year	10 Year
Base Rate Discounts	Year 1	10%	10%	10%	20%	20%	30%	30%	40%	40%	40%
	Year 2	- NA -	10%	10%	10%	20%	20%	30%	30%	40%	40%
	Year 3	- NA -	- NA -	10%	10%	10%	20%	20%	30%	30%	40%
	Year 4	- NA -	- NA -	- NA -	10%	10%	10%	20%	20%	30%	30%
	Year 5	- NA -	- NA -	- NA -	- NA -	10%	10%	10%	20%	20%	30%
	Year 6	- NA -	- NA -	- NA -	- NA -	- NA -	10%	10%	10%	20%	20%
	Year 7	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	10%	10%	10%	20%
	Year 8	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	10%	10%	10%
	Year 9	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	10%	10%
	Year 10	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	- NA -	10%

Q. ARE THESE DISCOUNTS THE MINIMUM CHARGES THAT PUBLIC SERVICE WILL ASSESS TO EDR CUSTOMERS?

A. For EDR customers between three and 20 MW, these reflect both the minimum and maximum charges Public Service will charge under Standard EDR Contracts. The Company is not seeking to establish a range of charges that would bind individually negotiated rates under Non-Standard EDR Contracts. Instead, the Company is proposing to establish a standardized discount rate applicable to all qualifying customers. Ms. Hollie Velasquez Horvath explains in her Direct Testimony how offering a standard discount structure will reduce the scope, and therefore the expense, of negotiations with prospective EDR customers, which benefits the Company and customers.

The Company will continue to pursue negotiated rates for customers greater than 20 MW and as individual circumstances otherwise warrant and will address the regulatory implications of any such Non-Standard Contract arrangements on a case-by-case basis as described below. For smaller customers with three to 20 MW of qualifying load, however, these will be the standardized discounts available through the proposed Schedule EDR and Standard EDR Contract; as I explain in more detail in Section VII, these proposed discounts are well-above the forecasted marginal cost of service.

Q. WHAT NON-BASE RATE ADJUSTMENTS WILL EDR CUSTOMERS PAY UNDER THE EDR TARIFF?

A. EDR customers will pay a modified ECA charge, a modified DSMCA charge and the Renewable Energy Standard Adjustment ("RESA") charge.[3] EDR customers will not pay the Purchased Capacity Cost Adjustment ("PCCA"), the Clean Air - Clean Jobs Act Rider ("CACJA"), the Transmission Costs Adjustment ("TCA"), the General Rate Schedule Adjustment ("GRSA"), nor the General Rate Schedule Adjustment – Energy ("GRSA-E").

The EDR ECA Factor is based on the estimated marginal cost of energy, which is primarily the cost of fuel and purchased energy. The Company proposes to update this value quarterly, as I discuss in more detail below. The Company's proposed DSMCA modifications will ensure EDR customers pay the full costs of DSM programs through their applicable DSMCA charge, including the portion of those costs that would otherwise be recovered through base rate charges if they were a non-EDR customer. This modification will ensure that EDR customers pay their full share of the costs of energy conservation programs, and that they will be eligible to participate in one of the Company's DSM programs. The Company recently proposed to modify and rename the DSMCA. In its 2021-2023 Transportation Electrification Plan ("TEP"), Proceeding No. 20A-0204E, the Company proposed to add the costs of its

[3] EDR customers will also pay the low-income Electric Affordability Program ("EAP") charge that is embedded in the standard S&F charge.

electric vehicle programs to the DSMCA and rename the rider the Customer Program Cost Adjustment ("CPCA"). EDR customers would not be charged the TEP portion of the CPCA Rider, only the full costs of the DSMCA as described above.

Q. WHY IS THE COMPANY PROPOSING EDR CUSTOMERS NOT PAY THE PCCA, CACJA, TCA, GRSA, OR GRSA-E CHARGES?

A. The Company's proposal that EDR customers not pay the PCCA, CACJA, TCA, GRSA, and GRSA-E is consistent with the Commission's Decision in the Black Hills EDR Proceeding.[4] The costs in these rate riders are related to embedded system costs and not reflective of the incremental cost to serve EDR customers. Furthermore, the Company is planning to eliminate the GRSA, and GRSA-E in its upcoming Phase II rate case. Also, the CACJA Rider will soon be eliminated with all costs rolled into base rates pending one final true-up, as authorized by the Commission's Decision in the Company's 2019 Phase I Electric Rate Case in Proceeding No. 19AL-0268E.[5]

[4] Decision No. C19-0446 in Proceeding No. 18A-0719E, at ¶ 67.
[5] Decision No. C20-0096 in Proceeding No. 19AL-0268E, at ¶¶ 357-360.

Q. THE COMPANY RECENTLY PROPOSED TO CREATE TWO NEW RIDERS, THE WILDFIRE PROTECTION RIDER ("WPR"), AND THE ADVANCED GRID RIDER ("AGR"), WOULD EDR CUSTOMERS PAY EITHER OF THESE TWO RIDERS?

A. No, both riders have only recently been filed and are pending Commission approval. However, similar to the other riders I identified above that are excluded, these riders, as proposed, will recover embedded system costs and are therefore not associated with the marginal cost to serve EDR customers. Wildfire protection is an issue that must be addressed regardless of whether any new EDR customers enroll. Nor will the eligible WPR costs be influenced by additional EDR customers. Similar to wildfire, eligible AGR costs will not change as a result of new EDR customers.

Q. WHAT IS THE IMPACT OF THE PROPOSED BASE RATE DISCOUNTS AND THE NON-BASE RATES ADJUSTMENTS FOR EDR CUSTOMERS?

A. In Section VI of my Direct Testimony, I provide an analysis of the total discounts the Company's EDR would provide. Under the Company's current retail rates, a customer with a peak demand of 10 MW and an 80 percent load factor using PG service would realize an initial 38.8 percent reduction in their electric bill, which will gradually decrease over the 10-year term of the customer's EDR contact. Table SWW-D-3 provides an illustrative example of the bill impacts this customer would experience in the first year of the Standard EDR Contract. Bill savings in subsequent years will be smaller as the base rate discounts are phased out.

Table SWW-D-3 – Economic Development Rate Bill Impact

Primary General	Volumes	Standard Rates	Economic Development Rates	Standard Bill	Economic Development Bills	Difference	
Service and Facility Charge	80.00% L.F.	$346.29	0%	$346	$346	$0	
Energy Charge	5,840,006 kWh	$0.00458 /kWh	-40%	$26,747	$16,048	($10,699)	
Distribution Demand Charge	10,000 kW	$3.86 /kW	-40%	$38,600	$23,160	($15,440)	
G & T Demand Charge	10,000 kW	$11.12 /kW	-40%	$111,200	$66,720	($44,480)	
Base Rate Subtotal				$176,894	$106,275	($70,619)	-39.9%
GRSA		5.76%	0.00%	$10,189	$0	($10,189)	
GRSA-E		$0.00410 /kWh	$0.00 /kWh	$23,944	$0	($23,944)	
Base Rate Subtotal+GRSA				$211,027	$106,275	($104,752)	-49.6%
DSMCA	10,000 kW	$0.65 /kW	$1.74 /kW	$6,500	$17,400	$10,900	
PCCA	10,000 kW	$1.15 /kW	$0.00 /kW	$11,500	$0	($11,500)	
CACJA	10,000 kW	-$0.02 /kW	$0.00 /kW	($200)	$0	$200	
TCA	10,000 kW	$0.10 /kW	$0.00 /kW	$1,000	$0	($1,000)	
ECA - On Peak	2,338,661 kWh	$0.02984 /kWh	$0.02179 /kWh	$69,777	$50,950	($18,827)	
ECA - Off Peak	3,501,345 kWh	$0.02086 /kWh	$0.01535 /kWh	$73,054	$53,750	($19,305)	
Non-Base Rate Adjustment Subtotal				$161,632	$122,100	($39,532)	-24.5%
Total Bill Before RESA				$372,659	$228,375	($144,284)	-38.7%
RESA		2.00%	2.00%	$7,453	$4,567	($2,886)	
Total Monthly Bill				**$380,112**	**$232,942**	**($147,170)**	**-38.7%**
Total Annual Bill				**$4,561,341**	**$2,795,306**	**($1,766,035)**	**-38.7%**

Q. HOW IS THE COMPANY PROPOSING TO MODIFY ITS DISTRIBUTION EXTENSION POLICY FOR EDR CUSTOMERS?

A. The Company's Distribution Extension Policy provides that the Company will install, at its expense, the necessary on-site distribution facilities required to serve a new customer up to the average gross embedded distribution plant costs of the overall system. To ensure that EDR customers will pay at least the marginal cost to serve them, the Company proposes to eliminate the upfront construction allowance, and that EDR customers pay in advance for the full cost of any distribution upgrades necessary for service. An illustrative example of these proposed changes is included in Attachment SWW-2, which contains a redline markup of the Company's current Distribution Extension Policy (Attachment SWW-3 contains the clean version). Public Service would execute these changes through a separate compliance advice letter filing if the Commission approves the Company's proposals in this proceeding.

Q. HOW DOES THE COMPANY PROPOSE TO REPORT ON EDR SALES TO THE COMMISSION?

A. The Company proposes to make an annual filing with the Commission that will report the total aggregate sales to and revenues from EDR customers. The report will also include an estimate of what EDR customers would have paid under Public Service's standard tariff rates, so the Commission and interested stakeholders can assess the magnitude of the discounts provided under the Company's illustrative EDR tariff. The report will not include a re-assessment of marginal costs nor will the Company keep separate books and records for EDR customers and associated investments, as the Company's proposal ensures that an EDR customer's net bills will be substantially above the marginal cost of service, consistent with C.R.S. § 40-3-104.3.

Q. HOW DOES THE COMPANY PROPOSE TO TREAT EDR CUSTOMERS AND THEIR ASSOCIATED REVENUES IN RATE CASE PROCEEDINGS?

A. When determining the total aggregate revenue deficiency, revenues from EDR customers will be treated like all test year revenues, as an offset to test year costs for purposes of establishing the Company's revenue requirement deficiency. Consistent with C.R.S. § 40-3-104.3, the discounts provided to EDR customers will not be imputed as revenue for the Company.

For the purpose of class cost allocation, typically conducted as part of a Phase II rate case proceeding, EDR customer load will not be included in any rate class and the base rate revenues from EDR customers will be treated as "other revenue." As I explain in Section VIII of my Direct Testimony, this approach ensures that cost allocations to specific rate classes will not increase as a result of the EDR, and that the benefits of incremental EDR revenues are shared with all customers.

Q. HOW WILL CUSTOMERS QUALIFY FOR THE EDR TARIFF?

A. The illustrative EDR tariff provides the terms and conditions necessary to qualify for the EDR discount consistent with Colorado's enabling legislation. First, as explained by Ms. Velasquez Horvath's Direct Testimony, the Company will work with the prospective EDR customer to confirm that that the customer meets the statutory eligibility requirements to receive an EDR discount, and the prospective EDR customer will sign an affidavit providing the factual support for such eligibility. Second, the Company will negotiate and enter into an EDR contract with the customer. Ms. Velasquez Horvath includes the Company's planned Standard EDR Customer Service Agreement for Standard EDR Contracts as Attachment HVH-2 to her Direct Testimony and describes its key terms and conditions. Third, as described in more detail below, the Company will file a notice of the customer's enrollment that includes the EDR Customer Service Agreement between the Company and the customer and the customer's affidavit demonstrating eligibility, both filed on a confidential basis. These filings will provide the Commission an opportunity to review the eligibility of EDR customers taking standard base rate discounts under the EDR tariff as the Company enters these contracts. When a prospective EDR customer's load is 20 MW or greater, or the EDR contract provides for a discount different from the EDR tariff discount, the Company would seek Commission approval for this Non-Standard EDR Contract to move forward, with the Company filing an application and initiating a new proceeding and demonstrating the customer's eligibility and that the Non-Standard EDR Contract is consistent with C.R.S. § 40-3-104.3. I describe the Company's requested expedited procedural framework to address such applications in Section X below.

Q. WHY IS AN EXPEDITED REVIEW AND/OR APPROVAL PROCESS NECESSARY FOR EDR CUSTOMERS?

A. As explained in Ms. Velasquez Horvath's Direct Testimony, the important business decision of where to locate or expand existing operations is often a time-sensitive one, and incentives like EDRs are most effective when they can be predictably relied upon. Public Service is concerned that the uncertainty associated with a protracted regulatory proceeding could deter prospective EDR customers from choosing Colorado and bringing the job-creating economic growth that HB 18-1271 is meant to promote. In turn, this delay could lead prospective EDR customers to choose another state where they could obtain an electricity discount through a more streamlined process.

Q. WILL THE COMPANY HAVE THE ABILITY TO EXPAND EXISTING RENEWABLE ENERGY PROGRAMS TO ACCOMMODATE EDR CUSTOMERS WHEN NECESSARY?

A. Yes. The economic development legislation specifically allows for the expansion of renewable energy programs to accommodate EDR customers. Ms. Velasquez Horvath addresses the importance of voluntary renewable energy programs to prospective EDR customers, and Company witness R. Neil Cowan provides more background on the Company's voluntary renewable energy programs that may be of interest to prospective EDR customers. He also explains the Company's expectation that such programs will need to be expanded to accommodate interest from EDR customers. I address the Company's proposed expedited procedural framework for the Commission to address requested expansions of the Company's existing voluntary renewable energy programs below.

III. STATUTORY REQUIREMENTS FOR ECONOMIC DEVELOPMENT RATES FOR QUALIFYING CUSTOMERS

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

A. In this section of my Direct Testimony, I discuss the statutory requirements that apply to utility EDRs in Colorado.

Q. WHAT ARE THE STATUTORY REQUIREMENTS FOR OFFERING ECONOMIC DEVELOPMENT RATES TO QUALIFYING CUSTOMERS?

A. C.R.S. § 40-3-104.3 expanded the existing special contract rate statute by adding sections 6 and 7 to C.R.S. § 40-3-104.3, which now includes the following required parameters for EDRs and contracts:

1) The EDR must be lower than the utility's standard C&I rates.[6]

2) The EDR must be higher than the utility's marginal cost of service.[7]

3) The utility may offer an EDR to qualifying customers for up to 10 years.[8]

4) To qualify for the EDR, a customer must add at least three megawatts of new load at a single location or expand existing operations by three megawatts.[9]

5) Utilities may enter into EDR contracts for load between three and 20 megawatts without Commission approval so long as the contract complies with the Commission-approved EDR tariff.[10]

6) The Commission will not impute to the utility the value of the EDR discount.[11]

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[6] C.R.S. §40-3-104.3(6)(b)(I)).
[7] C.R.S. §40-3-104.3(6)(b)(I)).
[8] C.R.S. §40-3-104.3(6)(b)(III).
[9] C.R.S. §40-3-104.3(7)(a)(I)(A).
[10] C.R.S. §40-3-104.3(6)(b)((II)(B).
[11] C.R.S. §40-3-104.3(6)(c)(III).

In essence, these provisions allow utilities to provide electric rate discounts to attract new or expanded business to Colorado without charging the cost of the discounts back to the utility. The requirement that the EDR be above the marginal cost of service to a given customer is a critical element of the EDR statute and ensures that other customers are not harmed by the EDR, or that other customers are not subsidizing customers on the EDR.

Q. DOES C.R.S. § 40-3-104.3 PROVIDE ANY GUIDANCE ON COMMISSION APPROVAL OF AN EDR?

A. Yes, the statute specifies that in an application for approval of an EDR the utility bears the burden of proof to establish that:

1) The charges assessed to other customers do not subsidize the EDR for qualifying customer.[12]

2) The rates of other utility operations do not increase.[13]

3) Other customers on the utility's system do not experience rate increases as a result of the EDR.[14]

These three criteria are all related to the concept that an EDR customer must pay at least as much as the incremental cost to serve them. This is also same as the C.R.S. § 40-3-104.3 provision that an EDR must be above the marginal cost of service. The Company's Application and supporting testimony filed in this proceeding meets the burden of proof specified in statute, by showing that the proposed EDR base rate discounts and non-base rate adjustments result in

[12] C.R.S. §40-3-104.3(6)(c)(II)(A).
[13] C.R.S. §40-3-104.3(6)(c)(II)(B).
[14] C.R.S. §40-3-104.3(6)(c)(II)(C).

charges that are above the marginal cost of service for EDR customers. The Company's conservative approach to designing its proposed EDR allows the Commission to make this determination now and avoids the need to frequently revisit the question of marginal cost.

Q. WITH REGARD TO EDR TERMS AND CONDITIONS, WHAT DOES C.R.S. § 40-3-104.3 REQUIRE?

A. C.R.S. § 40-3-104.3(6)(b)(II) authorizes the Commission to approve an EDR and "set a minimum and maximum amount for the rate." And, C.R.S. § 40-3-104.3(6)(c)(I) states that Commission authorization of an EDR "must include such terms and conditions as the Commission determines are necessary to ensure that the Economic Development Rates or charges assessed to other customers do not subsidize the cost of providing service to qualifying commercial and industrial customers."

Q. DO THE TERMS AND CONDITIONS IN THE COMPANY'S ILLUSTRATIVE EDR TARIFF COMPLY WITH THESE STATUTORY REQUIREMENTS?

A. Yes. The standardized base rate discounts reflect both the minimum and maximum charges required by C.R.S. § 40-3-104.3(6)(b)(II). My impression is that the legislation contemplated that each EDR contract would be individually negotiated within a range of potential charges, but nothing in the legislation precludes utilities from offering a standardized base rate discount to qualifying EDR customers. While the flexibility associated with a range of potential discounts may be appropriate for very large EDR customers, the Company is seeking to establish a standardized discount for smaller customers between three and 20 MW that complies with the statute by setting the minimum charge equal to the maximum charge.

Public Service's illustrative EDR tariff also complies with the requirement that it contain terms and conditions necessary to avoid subsidization (C.R.S. § 40-3-104.3(6)(c)(I)). These terms and conditions include: modifications to the Company's Distribution Extension Policy, as reflected in Attachments SWW-2 (redline) and SWW-3 (clean); fixed base rate discounts that phase out over time; and the modifications to non-base rate adjustments (i.e. DSMCA and ECA). As I demonstrate later in my Direct Testimony, these provisions combined ensure that EDR customers are paying more than the marginal cost to serve them and that no subsidization will occur.

Q. HOW DO THE EDR DISCOUNTS AUTHORIZED UNDER HB 18-1271 COMPARE WITH THE DISCOUNTS ALREADY AUTHORIZED UNDER C.R.S. § 40-3-104.3?

A. C.R.S. § 40-3-104.3 (1) through (5) provides the conditions under which an electric, gas, or steam utility can offer special contract rates "without reference to its tariffs on file with the Commission." As Staff witness Ms. Erin O'Neill explained in her Answer Testimony in the Black Hills EDR Proceeding, these provisions were designed to provide a means for utilities to retain existing customers who indicate an intention to leave the utility's system but for the special rate.[15] Ms. O'Neill explained that EDRs differ from these pre-existing special contract rates in at least five ways:

- EDRs may not be above tariff rates while other special contract rates could come to exceed tariff rates;
- EDRs have a maximum contract term of 10 years while other special contract rates do not have a statutorily-limited duration;
- EDR qualifying customers must add at least three megawatts of incremental load at a single location while there is not a statutory minimum load limit for other special contracts;
- While utilities can enter into EDR contracts for customers adding incremental load between three and 20 MW pursuant to a Commission-approved EDR tariff without separate Commission approval, Commission approval is required for other special rate contracts; and,
- For EDR contracts, the Commission shall not impute to the utility revenues that would have been received from the qualifying commercial or industrial customer if the customer were being provided service under the corresponding rate for which it would have otherwise qualified under the utility's tariffs.[16]

Public Service agrees with Staff's assessment.

[15] Erin T. O'Neill Answer Testimony ("O'Neill Answer Testimony") at 11:7-11, Proceeding No.18A-0791E.
[16] O'Neill Answer Testimony at 14:8-12, Proceeding No. 18A-0791E.

IV. BLACK HILLS' EDR PROCEEDING NO. 18A-0791E

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

A. In this section of my Direct Testimony, I discuss Black Hills' recent EDR filings, which included a proposed EDR tariff filing and customer-specific EDR contract filing. Both filings were consolidated into Proceeding No. 18A-0791E. While the Commission's decision from that case is not binding on Public Service, I explain how the Company has considered and incorporated the Commission's findings into its EDR proposal here.

Q. PLEASE PROVIDE A SUMMARY OF BLACK HILLS' EDR PROCEEDING.

A. Black Hills' EDR Proceeding No. 18A-0791E was a consolidated proceeding that included (1) an application requesting approval of a new EDR tariff to implement EDR rates pursuant to C.R.S. § 40-3-104.3; and (2) a subsequently-filed application requesting expedited approval of a service agreement Black Hills negotiated with a data center under the terms of its proposed EDR tariff (which were both subsequently consolidated into a single proceeding). In its final Decision (Decision No. C19-0446, as modified by its decision on rehearing, Decision No. C19-0656), the Commission did not approve an EDR tariff of general applicability, but instead approved a modified version of Black Hills' EDR tariff, including the requirement that the tariff would only apply to the data center customer with who Black Hills had entered into a service agreement. The Commission also approved the service agreement, again, subject to certain conditions.

Q. DOES THE DECISION IN BLACK HILLS' EDR PROCEEDING ESTABLISH PRECEDENT FOR PUBLIC SERVICE'S PROPOSAL?

A. I am not a lawyer, but my understanding is that none of the Commission's findings in Proceeding No. 18A-0719E are binding to Public Service. The Company has nonetheless reviewed the Commission's Decision[17] in that proceeding and crafted its proposal here to address and respond to many of the issues the Commission identified.

Q. WHAT ARE SOME OF THE KEY FINDINGS FROM THE COMMISSION'S DECISION IN THE BLACK HILLS EDR PROCEEDING?

A. With respect to Black Hills' EDR tariff proposal, among other things, the Commission found:

- An EDR tariff should establish minimum and maximum EDR rates;
- An EDR tariff should include "a quantification of, or at least some formulation or definition of marginal cost," to provide the information needed to ensure the statutory requirements for an EDR tariff are met, and to ensure no prohibited subsidization will occur.
- The Commission found Black Hills' proposed EDR tariff to lack clarity regarding how Black Hills plans to implement its line extension policies for new distribution infrastructure to prevent subsidization and how the policy would be reflected in the monthly rates billed and collected from EDR customers.
- Finally, the Commission discussed the need for Black Hills to show the exact rate mechanisms that would be used to collect the marginal cost, and provided clear direction on what non-base rate adjustments, or rate riders, should apply to EDR customers.

[17] Decision No. C19-0446, Proceeding No. 18A-0719E.

I address each of these topics, along with other relevant issues raised in Black Hills' proceeding, in turn below.

Q. DOES PUBLIC SERVICE'S PROPOSAL ADDRESS THE ISSUE OF MINIMUM AND MAXIMUM CHARGES?

A. In denying Black Hills' proposed EDR tariff as one of general applicability, the Commission found that the proposed tariff "fails to establish minimum and maximum rates and fails to provide a value for marginal cost or even present some formulation or definition of marginal cost."[18] The Decision went on to state that "the purpose of a tariff is to provide notice and transparency to the public of the terms under which the monopoly utility is authorized to provide service," and, by definition, a "tariff sets the *rates* that can be charged for the service provided."[19] Here, with respect to minimum and maximum charges, the Company is proposing a different discount structure than Black Hills. Instead of proposing a range of discounts, we are proposing a singular percentage discount that will gradually diminish over time, rather than a minimum and maximum range of discounts. Each tier of our proposed discount structure therefore amounts to the minimum and maximum rate that will apply to the qualifying customer. As Ms. Velasquez Horvath explains in more detail in her Direct Testimony, the Company believes this approach is more efficient, provides more certainty, and will help streamline the negotiation process with potential EDR customers. This

[18] Decision No. C19-0446, at ¶ 61.
[19] Decision No. C19-0446, at ¶ 61 (emphasis in original).

approach is also more consistent with economic development rates that are offered in other states.

Q. HOW DOES THE COMPANY'S EDR TARIFF ADDRESS MARGINAL COSTS?

A. The Company agrees with the definition of marginal cost adopted by Staff in Black Hills' proceeding:

> the change in the total cost that arises when the quantity produced is incremented by one unit; that is, it is the cost of producing one more unit of a good. Intuitively, marginal cost at each level of production includes the cost of any additional inputs required to produce the next unit.[20]

In Section VII of my Direct Testimony I provide additional discussion surrounding the definition of marginal costs and estimates of those values. The Company's objectives with its proposed EDR are to clearly articulate what short-term and long-term marginal costs are associated with EDR customers, to present a conservative estimate of those costs, and to demonstrate that the proposed EDR will result in total charges that are higher than the marginal costs of service. As the Commission found in its decision on rehearing in the Black Hills' proceeding, "[i]f parties in a future proceeding arrive at a robust definition that allows the Commission to confirm the EDR rate is at or above the utility's marginal cost, to expedite review of future agreements under the approved tariff, and to make the Commission's other required findings, they can present that proposal for our consideration."[21] Here, the Company has proposed a robust

[20] O'Neill Answer Testimony at 22:14-17, Proceeding No. 18A-0791E.
[21] Decision No. C19-0656, at ¶ 8.

process and definition of marginal cost that confirms its EDR will not drop below the Company's marginal cost.

Q. DOES C.R.S. § 40-3-104.3 REQUIRE THAT A $/KWH MARGINAL COST VALUE BE INCLUDED IN THE EDR?

A. No. The legislation does not specifically require the inclusion of a $/kWh marginal cost value. As I previously discussed, the legislation requires a minimum and maximum rate as well as terms and conditions necessary to avoid cross-subsidization. The Company's illustrative tariff complies with those requirements. In Section VII, I present an estimated value for the marginal cost of service, but that value is not included in the Company's illustrative EDR tariff. The Company's position is that the marginal cost estimate is only needed for the Commission to confirm that Public Service's proposed base rate discounts comply with statute and that setting forth the applicable methodology for calculating marginal cost *vis-à-vis* the tariff is reasonable and appropriate.

Q. DOES THE COMPANY'S PROPOSAL ADDRESS THE ISSUES ASSOCIATED WITH THE LINE EXTENSION POLICY THAT WERE IDENTIFIED IN BLACK HILLS' EDR PROCEEDING?

A. Yes. In its Decision, the Commission stated that "Black Hills relies on its line extension policy to avoid prohibited subsidization but fails to show how it will implement it to ensure this result," including, "how the policy will be reflected in the monthly rates billed and collected from EDR customers."[22] Public Service has considered and addressed these concerns in its proposal. In Section V of my Direct Testimony, I explain how the Company's existing Distribution Extension Policy addresses the cost of interconnecting new customers and how the Company proposes to modify that policy for EDR customers. The Company proposes to modify its Distribution Extension Policy to require EDR customers to make, in advance, a non-refundable construction payment that covers the entire cost of new distribution system infrastructure necessary to serve the customer. This aspect of the Company's proposal is a critical element that ensures that the short-term marginal costs of distribution service are paid directly by the qualifying EDR customer. An illustrative example of these proposed changes is included in Attachment SWW-2, which contains a redline markup of the Company's current Distribution Extension Policy (Attachment SWW-3 contains a clean version).

Q. IS THE COMPANY'S PROPOSAL FOR NON-BASE RATE ADJUSTMENTS CONSISTENT WITH THE COMMISSION'S DECISION IN BLACK HILLS' EDR PROCEEDING?

A. Yes. Paragraph 67 in Decision No. C19-0446 provided clear direction as to which rate riders the Commission believes should apply to EDR customers, and which should not:

> We agree with Staff that only three riders should apply by default: the DSMCA, the RESA, and the BHEAP fee. We agree with Staff that EDR customers should not be subject to the GRSA, ECA,

[22] Decision No. C19-0446, at ¶ 64.

> TCA, and PCCA, and we add the CACJA rider to this list. However, unlike Staff, we do not find sufficient support in this record to exclude from the calculation of the revenue requirements of those riders any costs associated with the provision of service to the EDR customers. Likewise, we do not find sufficient support in this record to not require any amount of revenues collected from EDR Tariff customers to be contributed toward these riders.[23]

Public Service's proposal is generally consistent with these findings but deviates slightly because the Company is recommending that a modified ECA rate be charged to EDR customers to cover the marginal cost of fuel and purchased power needed to serve EDR customers. This is consistent, however, with the Commission's intent that EDR customers should not pay the standard ECA rate, which includes the average cost of all fuel and purchased energy and is therefore not reflective of the marginal cost of energy.

Q. DID COMMISSION STAFF RAISE ANY ISSUES IN BLACK HILLS' EDR PROCEEDING THAT THE COMPANY WOULD LIKE TO ADDRESS HERE?

A. Yes. Among other things, Staff recommended (1) that an EDR customer should be defined to include all incremental or going-forward costs to serve the customer over the contracted period, and (2) Black Hills should be required to re-file its EDR Tariff annually to reflect non-zero marginal cost. While the Company generally agrees with Staff's recommendation regarding incremental cost, the Company is taking a different approach to Staff's proposal regarding tariff implementation.

[23] Decision C19-0446 in Proceeding No. 18A-0719E, at ¶ 67.

Q. SPECIFICALLY, WHAT WERE STAFF'S RECOMMENDATIONS REGARDING TARIFF IMPLEMENTATION?

A. Staff's Statement of Position in Proceeding No. 18A-0791E articulated Staff's recommendation for EDR tariff implementation. Pages 16 and 17 include the following five elements of Staff's proposal:

1) Creation of a separate rate class that tracks all base rate and rider costs associated with EDR customers;
2) An annual filing where all incremental costs, revenues, and net income associated with serving EDR customers are reported;
3) Crediting positive net income from EDR customers, after any sharing, with ratepayers through the ECA;
4) Marginal costs associated with EDR customers should be identified in other proceedings such as resource plans, transmission plans, and Certificates of Public Convenience and Necessity ("CPCN"); and,
5) Rate cases should also include an analysis of incremental costs.

Q. DID THE COMMISSION AGREE WITH ANY OF THESE RECOMMENDATIONS IN THE BLACK HILLS PROCEEDING?

A. The Commission declined to take a position on any proposals not expressly adopted in the Decision, including Staff's proposals to require Black Hills to create a separate EDR rate class and to report annually all incremental costs, revenues, and net income associated with serving EDR customers, stating that consideration of such proposals would be deferred to a future proceeding.[24] While the Commission approved Black Hills' request to provide its proposed

[24] Decision C19-0446, ¶ 72.

revenue sharing customer credit to other customers *via* the deferred account of the Company's ECA, it did not make any finding about whether revenue sharing is required. The Commission did not comment on Staff's proposals regarding the identification of marginal costs associated with EDR customers in other proceedings or Staff's proposal to include an analysis of EDR incremental costs in rate cases.

Q. DOES PUBLIC SERVICE AGREE THESE RECOMMENDATIONS SHOULD BE ADOPTED IN THIS PROCEEDING?

A. No. If these provisions were required, then the Company would not have sufficient incentive to expend resources to pursue EDR customers and would not likely seek to implement the Commission's decision on this Application.

Q. WHY?

A. The third provision is inconsistent with the intent of C.R.S. § 40-3-104.3 as it would effectively remove all economic incentive for the Company to pursue EDR customers, and the other four set up burdensome and unnecessary reporting requirements that would apply to at least five other regulatory proceedings. While I address revenue sharing in more detail in Section IX of my Direct Testimony, there is no precedent for the Commission to deny the Company incremental revenues associated with new customers and it removes the Company's financial incentives to attract new customers to Colorado, which contradicts C.R.S. § 40-3-104.3. Public Service has been enrolling new customers for over 100 years and has never been required to refund revenue from new customer growth. Neither C.R.S. § 40-3-104.3, nor any other statute or regulation the Company is aware of requires any such forfeiture and it is simply bad policy that may contribute to more frequent rate cases due to larger revenue deficiencies.

With regard to analyzing marginal costs associated with EDRs across multiple categories of proceedings (*e.g.* resource plans, transmission plans, and CPCN proceedings), this approach is not supported by the EDR statute, Commission precedent or policy, and would be administratively burdensome for little benefit. In Black Hills' proceeding, for instance, the Commission's decision on rehearing generally affirmed these principles, finding that it was unnecessary to require Black Hills to complete annual re-filings of its EDR Tariff with updated, non-zero marginal cost values.[25] Moreover, Public Service's conservative approach to its EDR tariff design eliminates this need. In Section VII of my Direct Testimony I show that short-run marginal costs are addressed by the Company's extension policy and that long-run marginal costs are lower than the rates included our illustrative EDR tariff.

[25] Decision No. C19-0656, at ¶¶ 9-15.

V. EDR DISTRIBUTION EXTENSION POLICY MODIFICATIONS; TRANSMISSION AND GENERATION POLICIES

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

A. In this section of my Direct Testimony, I explain the Company's proposed modifications to its Distribution Extension Policy for EDR customers. These modifications will ensure that EDR customers pay for the short-term marginal cost of distribution and transmission resources needed to serve them. Later in my Direct Testimony, I demonstrate how the discounted base rate charges are sufficient to cover the long-term marginal cost of distribution and transmission.

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT DISTRIBUTION EXTENSION POLICY AS IT APPLIES TO COMMERCIAL CUSTOMERS.

A. The Company's Distribution Extension Policy is set forth in Public Service's Electric Service Tariff on file with the Commission – the Distribution Extension Policy (COLO. PUC No. 8 Electric Sub. Original Sheet No. R200, *et seq.*). The Company also has a Transmission Line Extension Policy (COLO. PUC. No. 8 Electric Original Sheet No. R195, *et seq*.), which I discuss later.

Under its current, Commission-approved Distribution Extension Policy, when a new or existing customer makes a request to interconnect new load to Public Service's distribution system, the Company reviews the request to see if there is sufficient capacity to serve the new load. In the event additional distribution facilities are needed, the Company will require the customer to make an upfront construction payment to cover those costs. However, a portion of the construction payment is offset by a construction allowance, which is paid by the Company and included in base rate revenue requirements for all customers.

Q. WHY IS THE DISTRIBUTION EXTENSION POLICY AN IMPORTANT PART OF THE COMPANY'S EDR PROPOSAL AND COMPLIANCE WITH C.R.S. § 40-3-104.3?

A. Line extensions are a fundamental and potentially sizable part of the marginal cost to serve EDR customers. The Company proposes to eliminate the construction allowance for EDR customers to ensure that they pay for the full cost of incremental distribution infrastructure needed for service. With this modification, the Commission will ensure that EDR customers are paying the short-term marginal cost of distribution, and other customers are not subsidizing them, consistent with C.R.S. § 40-3-104.3. It is possible that EDR customers could also contribute to the need for long-term distribution system investments not addressed through line extensions. I therefore also estimate the long-term marginal cost of distribution capacity to serve EDR customers in Section VII of my Direct Testimony. I estimate those costs in Section VII of my Direct Testimony and demonstrate that the base rate discounts ensure the Company's proposed EDR discounts are above those long-run marginal costs.

Q. WHAT IS THE IMPACT OF ELIMINATING THE CONSTRUCTION ALLOWANCE FOR EDR CUSTOMERS?

A. Construction allowances are very important for new or expanding customers. For example, the Company's current construction allowance for PG customers is

$220/kW. This means that a 10 MW customer could receive a credit of up to $2.2 million for distribution system upgrades required to serve its load.

Q. HOW DOES ELIMINATION OF THE CONSTRUCTION ALLOWANCE COMPLY WITH THE REQUIREMENTS OF HB 18-1271?

A. By eliminating the construction allowance, an EDR customer would pay for all the distribution system upgrades up front and not be subsidized by any other customers.

Q. WHAT ARE OFF-SITE DISTRIBUTION LINE EXTENSIONS?

A. Off-site distribution line extensions extend service from the Company's existing distribution facilities to a customer's property and include primary and secondary feeders, transformers, and all appurtenant facilities.

Q. WHAT IS THE OFF-SITE DISTRIBUTION LINE EXTENSION CREDIT?

A. The off-site distribution line extension credit is a 35 percent credit that is applied to a customer's construction payment to account for the likelihood that other new customers will utilize portions of the off-site distribution line extension. When the Company constructs a new off-site distribution line extension, it is impracticable to design an extension to only have the capacity to serve the requesting customer. Also, other customers may utilize some of the available capacity designed to serve the requesting customer in the time it takes the requesting customer to bring their load online. Because the Company no longer has an open-extension policy that is reviewed over a 10-year period and because it would be inequitable to require the first customer to pay for all the distribution infrastructure that may then serve subsequent customers, the Company is proposing to reduce the construction payment by 35 percent. This amount was recently approved in Proceeding No. 18AL-0852E and was based on an analysis of how many subsequent customers took service from a new off-site distribution line extension during the first eight years.

Q. WILL EDR CUSTOMERS BE GIVEN THE OFF-SITE DISTRIBUTION LINE EXTENSION CREDIT?

A. Yes. The Company recommends that the off-site extension credit also be given to EDR customers. To the extent that EDR customers require off-site distribution line extensions, their required construction payment will include the cost of facilities that subsequent new customers in the area would need. Prior to Proceeding No. 18AL-0852E in which the Commission approved a 35 percent[26] upfront credit, customers were eligible to receive excess construction allowance and refunds during the 10-year open extension period. As such, EDR customers would be making construction payments in excess of the marginal cost to serve them. The 35 percent extension credit should be available to EDR customers to minimize the extent to which they may subsidize other customers that subsequently move into the area and are served by the EDR customer's line extension.

Q. IS THE COMPANY WILLING TO TRACK AND REPORT ON THE OFF-SITE DISTRIBUTION LINE EXTENSION ASSOCIATED WITH EDR CUSTOMERS?

A. Yes. The Company is willing to track and report on off-site distribution line extensions that were made specifically for EDR customers. By reporting on off-site distribution extensions for EDR customers, the Company will be able to demonstrate if additional customers have located in the area and are also using the new distribution facilities. The Company proposes to include when off-site distribution line extensions and associated credits are provided for EDR customers, and subsequent customers that connect to these line extensions in its annual EDR Report, which I discuss in more detail below in Section VIII.

Q. WHAT IF AN EDR CUSTOMER ALSO REQUIRES ADDITIONAL TRANSMISSION LINE INVESTMENTS TO SERVE THEIR LOAD?

A. The Company's Transmission Line Extension Policy requires the applicant to pay the Company for the entire construction cost for necessary transmission facilities. As such, under the current policy, EDR customers will pay for the short-term marginal costs of transmission infrastructure needed for service and no modification of the policy is necessary.

Q. WILL EDR CUSTOMERS BE REQUIRED TO PAY FOR THEIR SERVICE LATERAL?

A. Yes. The Company's Distribution Extension Policy requires all PG customers to pay for the full cost of a new service lateral upfront. SG customers receive a construction allowance of $1,430 to cover a portion of the costs of a new service lateral. That allowance will not be available to EDR customers. As such, the Commission can be assured the EDR customers are making up-front payments for the full marginal cost of their service laterals.

Q. IF THE EXISTING AND MODIFIED DISTRIBUTION EXTENSION POLICY ADDRESSES THE SHORT-TERM MARGINAL COST OF TRANSMISSION AND DISTRIBUTION RESOURCES RESPECTIVELY, HOW WILL THE SHORT-TERM MARGINAL COST OF GENERATION BE ADDRESSED?

A. Public Service's EDR tariff includes a provision that requires EDR customers to pay for the cost of generation resources that are acquired to serve the EDR customers at the outset of their contract. More specifically, the EDR tariff specifies that the EDR customer is responsible for the cost of any generation asset that is acquired specifically to serve that customer at the beginning of their contract period. As I explain later in my Direct Testimony, this provision is intended to address the short-term marginal cost of generation assets that may be needed to serve an EDR customer. This provision will only be needed if Public Service does not have sufficient system capacity to serve the customer at the outset of the contract. Also, this provision may be partially or wholly offset by the customer's participation in a voluntary renewable energy program that may include the acquisition of a renewable energy resource to serve the customer's load. The long-term marginal cost of generation will be covered by the discounted base rate charges assessed to EDR customers. This provision is intended to act as the generation equivalent to the Transmission Line Extension and Distribution Extension Policies, similarly ensuring no subsidization occurs.

VI. EDR TARIFF AND TOTAL DISCOUNT ANALYSIS

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

A. In this section of my Direct Testimony, I discuss the EDR tariff and non-base rate adjustments that will apply to EDR customers. I also provide an illustrative analysis of the total discounts that a customer with 10 MW of qualifying EDR load may receive.

Q. WILL THE EDR TARIFF BE OFFERED AS A STAND-ALONE SERVICE SCHEDULE?

A. No. EDR customers will be required to take service under one of the Company's standard C&I service schedules - SG, PG, or TG. The EDR tariff will provide a credit to the customer's bill and modifies the non-base rate adjustments that the customer must pay.

Q. WHAT DOES THE APPLICABILITY AND AVAILABILITY SECTION OF THE EDR TARIFF INCLUDE?

A. The applicability and availability section specifies that the EDR would be available to C&I Customers who: agree to locate in Colorado and add at least three MW of new load at a single location; or expand existing load in Colorado and add at least three MW of new load at a single location. To be eligible, a customer must also demonstrate, to the satisfaction of the Company, subject to review by the Commission, that the cost of electricity is a critical consideration in deciding where to locate new or expand existing operations and the availability of EDR. These requirements mirror the requirements in C.R.S. § 40-3-104.3.

Q. WHAT OTHER PROVISIONS DOES THE COMPANY'S EDR TARIFF INCLUDE?

A. The EDR tariff also requires that for customers expanding operations at an existing facility the new load must be separately metered so that the EDR base rate discounts can be applied correctly. The tariff also specifies the 10-year contract term and sets out rules for ensuring that the customer's load is between three and 20 MW. Other rules and regulations for EDR customers are covered by the standard C&I tariffs (SG, PG, or TG) that those customers will also be subject to.

Q. WHAT BASE RATE DISCOUNTS DOES THE EDR TARIFF SPECIFY?

A. The EDR tariff specifies that qualifying customer receive a discount on base rate demand and energy charges. Based on a 10-year contract, the discount is 40 percent in years one through three, then steps down to 30 percent for years four and five, 20 percent for years six and seven, and finally 10 percent for years eight through 10. The discounts do not apply to the customers' monthly S&F charges. This ensures that the customers are paying the full costs of metering and billing as well as the full low-income energy assistance program charge that is included in the S&F charge.

Q. WHAT COSTS ARE THE DISCOUNTED BASE RATE CHARGES INTENDED TO ADDRESS?

A. As I demonstrate later in my Direct Testimony, the discounted base rate charges will be sufficient to cover the long-term marginal cost of generation, transmission, and distribution costs. The base rate charges also cover the cost of variable operations and maintenance ("O&M") costs included in the base energy charge for C&I customers.

Q. WHAT NON-BASE RATE CHARGES WILL BE APPLICABLE TO EDR CUSTOMERS?

A. The Company recommends that customers taking service through its EDR tariff pay a modified ECA rate – the Economic Development ECA Factor ("EDR ECA Factor") – which is based on the marginal costs of energy, a modified DSMCA rate based on the total cost of Company run energy conservation programs, the RESA adjustment, and upon Commission approval the Colorado Energy Plan Adjustment ("CEPA") adjustment. An illustrative example of our proposed changes to the ECA and DSMCA is included in Attachments SWW-2, which contains a redline markup of the Company's tariffs (Attachment SWW-3 contains clean versions). Public Service proposes to execute these changes through a separate compliance advice letter filing(s) if the Commission approves the Company's proposals in this proceeding.

A. Economic Development Rate ECA Factor

Q. PLEASE DESCRIBE THE MARGINAL COST ECA THAT WOULD APPLY TO EDR CUSTOMERS.

A. The EDR ECA Factor will charge EDR customers ECA charges based on the marginal costs of energy instead of the total average cost of energy. The charge will be on a per kWh basis and utilize the same on-peak and off-peak time periods as the Company's other C&I ECA charges, to the extent applicable. The rate will be updated quarterly and will include the same deferred balance adjustment as the other ECA charges, ensuring that EDR customers only pay actual ECA costs.[27]

The primary difference will be that the marginal cost EDR ECA Factor will be based on a forecast of marginal costs instead of average energy costs for each quarter. Average ECA costs are a blend of wind, solar, natural gas, and coal fuel costs along with purchased power expenses, RESA adjustments, and other miscellaneous adjustments. Because the marginal cost of energy will likely be heavily influenced by the price of natural gas, it is possible that the marginal ECA rate will be higher than the standard ECA rate.

Q. HOW WILL THE EDR ECA FACTOR COMPARE TO THE ECA CALCULATION APPLIED TO C&I CUSTOMERS?

A. Due to currently low gas prices, the marginal costs of energy will be lower than the average cost of energy. Over the long term, the marginal cost of energy may be more variable than the average cost of energy, which includes a proportion of long-term purchased power contracts that have fixed or gradually escalating prices. To develop a comparison between the standard ECA charge and the EDR ECA Factor, I used data from the Company's last annual ECA filing,

[27] The ECA deferred balance adjustment calculates the running total of the difference between forecast ECA costs and actual ECA costs.

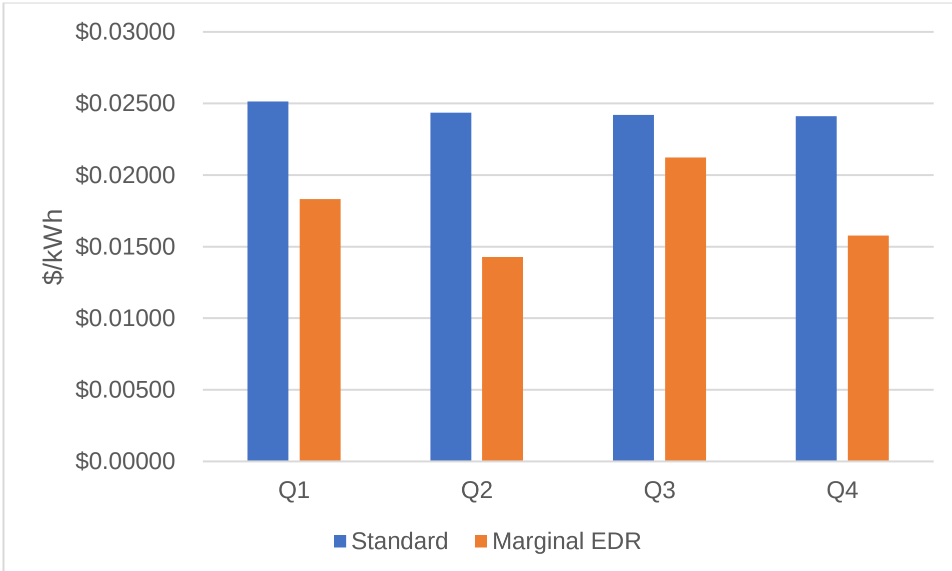
Proceeding No. 19A-0606E. This included forecasts for 2020 ECA rates[28] and an hourly marginal cost estimate, which are used to establish on-peak to off-peak price ratios for the ECA. The only modifications I made were to remove the Rush Creek costs that were moved into base rates in the Company's last Phase I Electric Rate Case, Proceeding No. 19AL-0268E, and to include a hypothetical deferred cost balance to demonstrate how it will be included in the marginal EDR ECA Factor. Table SWW-D-4 and Figure SWW-D-1 compare the 2020 forecasted ECA charges for a non-EDR primary voltage customer to the EDR ECA Factor applicable to a primary voltage EDR customer.

Table SWW-D-4 – Illustrative 2020 ECA Impact for Non-EDR Customer Versus EDR Customer

	Q1 2020		**Q2 2020**		**Q3 2020**		**Q4 2020**	
	Standard	Marginal EDR	Standard	Marginal EDR	Standard	Marginal EDR	Standard	Marginal EDR
Energy Cost	$0.02737	$0.01766	$0.02789	$0.01470	$0.02553	$0.02039	$0.02771	$0.01663
Chyenne Ridge					$0.00093		$0.00318	
Wind PTCs	($0.00252)		($0.00251)		($0.00252)		($0.00523)	
Wind Cost Sharing	$0.00017		$0.00011		$0.00009		$0.00010	
RESA Transfer	($0.00066)		($0.00064)		($0.00061)		($0.00067)	
R*C Payments	$0.00013		$0.00022		$0.00017		$0.00012	
Short-Term Margins			($0.00028)		($0.00024)		($0.00027)	
MEP							$0.00001	
Deferred Balance	$0.00066	$0.00066	($0.00043)	($0.00043)	$0.00086	$0.00086	($0.00084)	($0.00084)
Total	**$0.02515**	**$0.01833**	**$0.02436**	**$0.01427**	**$0.02421**	**$0.02124**	**$0.02411**	**$0.01578**
On-Peak Rate	$0.03068	$0.02190	$0.02972	$0.01811	$0.02953	$0.02787	$0.02941	$0.01926
Off-Peak Rate	$0.02146	$0.01750	$0.02078	$0.01218	$0.02065	$0.01771	$0.02057	$0.01402
Ratio	1.43	1.25	1.43	1.49	1.43	1.57	1.43	1.37

[28] The Annual ECA filing is only a forecast of expected rates. Actual ECA rates are set in separate monthly ECA filings.

Figure SWW-D-1 – Illustrative 2020 ECA Impact For Non-EDR Customer Versus EDR Customer



B. <u>Economic Development Rate DSMSCA</u>

Q. PLEASE DESCRIBE THE FULL COST EDR DSMCA

A. The “full-cost” EDR DSMCA charge applicable to EDR customers will be similar to the standard DSMCA charge applicable to non-EDR customers, except that it will include the full cost of DSM programs and incentives to capture DSM charges that are otherwise recovered through base rates, and which EDR customers would not otherwise pay under the EDR’s discounted base rates. For the past several years, a portion of the Company’s DSM program costs have been included in base rates. In the Company’s 2019 Electric Rate Case, for example, (Proceeding No. 19AL-0268E), $89,714,467 of DSM costs were included in base rates, while the current DSMCA rider includes $47,213,427. The DSMCA charge for EDR customers will be based on the full $136,927,894 ($89,714,467 + $47,213,427). The current DSMCA charge for PG customers is

$0.65/kW-month. Based on the same data, the full cost EDR DSMCA applicable to EDR customers would be $1.74/kW-month. By having EDR customers pay the full DSMCA, this will ensure EDR customers pay for their share of DSM programming and continue to have access to the robust suite of programming that many C&I customers enjoy.

Q. ARE THERE ANY ONGOING REGULATORY PROCEEDINGS THAT MAY IMPACT THE COMPANY'S DSMCA PROPOSAL?

A. Yes. Public Service recently proposed to modify and rename the DSMCA in its 2021-2023 TEP, Proceeding No. 20A-0204E. There, the Company proposed to add the costs of its electric vehicle programs to the DSMCA and rename the rider the CPCA (Customer Program Cost Adjustment). If this proposal is approved, EDR customers would not be charged the TEP portion of the CPCA Rider, only the full costs DSMCA as described above. While Public Service is providing an illustrative example of our proposed changes to the DSMCA in Attachments SWW-2 (redline) and SWW-3 (clean), assuming a final decision is issued in Proceeding No. 20A-0204E when the Company files its compliance advice letter filings related to this proceeding, it would incorporate the necessary changes accordingly.

C. Other Non-Base Rate Adjustments

Q. WHAT OTHER NON-BASE RATE ADJUSTMENTS WILL EDR CUSTOMERS PAY?

A. Because the EDR base rate discounts will not apply to the monthly S&F charge, EDR customers will also be paying the full cost of the low-income Energy Assistance Program, which is embedded in that charge. EDR customers will also pay the two percent RESA. Note that the Company recently proposed to reduce the RESA to one percent and add a one percent CEPA in Proceeding No. 20AL-0191E. If approved, EDR customers will also pay the CEPA. Either way there will be a two percent adjustment on EDR customers' bills. EDR customers will also pay the taxes and fees that appear on all customer bills.

Q. WHAT WILL BE THE TOTAL IMPACT OF THE EDR BASE RATE DISCOUNTS AND CHANGES TO THE NON-BASE RATE ADJUSTMENTS?

A. Based on 2020 rates, EDR customers' net monthly bill will be 38.8 percent lower than it would be under standard rates. The 40 percent reduction in base energy and demand charges has an obvious impact on monthly bills, but the elimination of GRSA adjustments creates an additional reduction and the overall base rate reduction is 49.6 percent. The reduction in non-base rate adjustments is 24.5 percent. To develop these estimates, I constructed a typical monthly bill comparing an average non-EDR PG customer under standard rates and an EDR PG customer taking service under the Company's EDR proposal. Table SWW-D-5 provides this analysis.

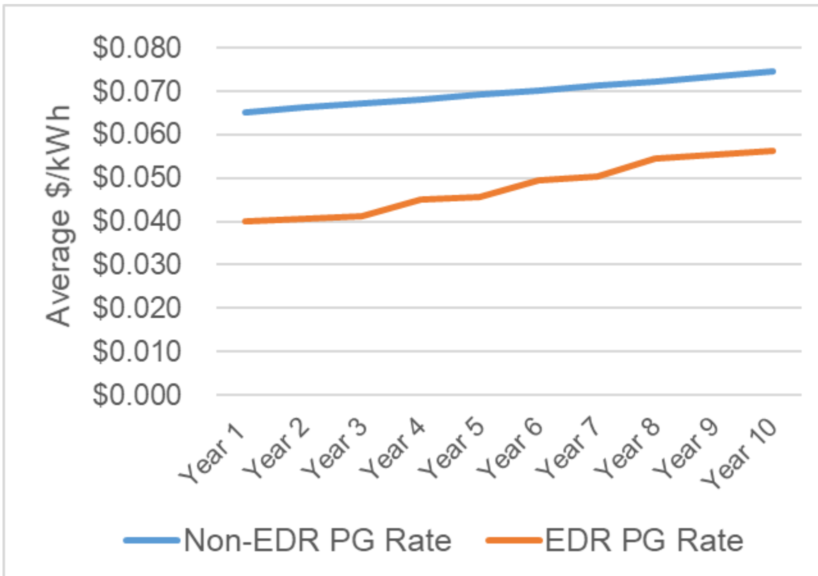
Table SWW-D-5
Average Non-EDR PG Customer Versus EDR PG Customer
1st Year 40% Base Rate Discount

	Volumes	Standard Rates	Economic Development Rates	Standard Bill	Economic Development Bills	Difference	
Primary General							
Service and Facility Charge	80.00% L.F.	$346.29	0%	$346	$346	$0	
Energy Charge	5,840,006 kWh	$0.00458 /kWh	-40%	$26,747	$16,048	($10,699)	
Distribution Demand Charge	10,000 kW	$3.86 /kW	-40%	$38,600	$23,160	($15,440)	
G & T Demand Charge	10,000 kW	$11.12 /kW	-40%	$111,200	$66,720	($44,480)	
Base Rate Subtotal				$176,894	$106,275	($70,619)	-39.9%
GRSA		5.76%	0.00%	$10,189	$0	($10,189)	
GRSA-E		$0.00410 /kWh	$0.00 /kWh	$23,944	$0	($23,944)	
Base Rate Subtotal+GRSA				$211,027	$106,275	($104,752)	-49.6%
DSMCA	10,000 kW	$0.65 /kW	$1.74 /kW	$6,500	$17,400	$10,900	
PCCA	10,000 kW	$1.15 /kW	$0.00 /kW	$11,500	$0	($11,500)	
CACJA	10,000 kW	-$0.02 /kW	$0.00 /kW	($200)	$0	$200	
TCA	10,000 kW	$0.10 /kW	$0.00 /kW	$1,000	$0	($1,000)	
ECA - On Peak	2,338,661 kWh	$0.02984 /kWh	$0.02179 /kWh	$69,777	$50,950	($18,827)	
ECA - Off Peak	3,501,345 kWh	$0.02086 /kWh	$0.01535 /kWh	$73,054	$53,750	($19,305)	
Non-Base Rate Adjustment Subtotal				$161,632	$122,100	($39,532)	-24.5%
Total Bill Before RESA				$372,659	$228,375	($144,284)	-38.7%
RESA		2.00%	2.00%	$7,453	$4,567	($2,886)	
Total Monthly Bill				**$380,112**	**$232,942**	**($147,170)**	**-38.7%**
Total Annual Bill				**$4,561,341**	**$2,795,306**	**($1,766,035)**	**-38.7%**

Q. HOW WILL THE EDR TARIFF IMPACT EDR CUSTOMER BILLS OVER THE TEN-YEAR TERM OF AN EDR CONTRACT?

A. The exact impact of the EDR tariff will depend on what changes happen to base rate charges, the EDR ECA Factor, and DSMCA charges over the 10-year period. However, to provide a quantitative example, I created a hypothetical 10-year projection that assumed rates generally increase at two percent per year. Figure SWW-D-2 shows that EDR customer bills will remain below the cost of non-EDR rates, but the difference diminishes over time as the base rate discounts are phased out. The figure does not reflect the elimination of the construction allowance for EDR customers, as this is highly customer-specific, though may be a significant cost. While this analysis is for a PG customer, I expect the results would be similar for SG or TG customers.

Figure SWW-D-2
Average PG Customer – Non-EDR Rates Versus EDR Rates
10-Year Contract Term



VII. MARGINAL COST DEFINITIONS AND ESTIMATES

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

A. In this section of my testimony, I provide definitions for a number of key marginal costs that underlie the Company's EDR proposal. Table SWW-D-6 provides a summary of how the Company has defined and calculated marginal costs for purposes of this proceeding. I discuss each in more detail below.

Table SWW-D-6
Summary of Marginal Cost Definitions

Marginal Cost Category	Definition/Calculation
Customer Costs	Equal to the standard customer costs associated with meters, meter reading, billing, and customer service.
Distribution & Transmission Costs	Short-term costs are equal to the cost to immediately interconnect EDR customers. The long-term costs are equal to the cost of advancing the timing of or increasing the size of investments in system reliability as a result of increased load.
Generation Capacity Costs	Short-term costs are equal to the costs of acquiring new capacity to serve the EDR customer, if needed. The long-term costs are equal to the weighted average between market capacity and the cost of a new combustion turbine.
Energy Costs	Equal to the incremental costs associated with fuel, purchased energy, and Variable O&M incurred to serve the additional load from EDR Customers. The marginal cost is determined through system dispatch simulations.
DSM Costs	No incremental DSM costs are expected to be caused by EDR customers.
Allocated Corporate Services	Increased share of corporate services costs associated with increased load and revenues from EDR customers.
Taxes & Fees	The incremental cost of franchise fees, occupation taxes, and sales taxes assessed to all utility bills.

I conclude this section with a comparison of the forecasted marginal cost to serve an EDR customer to the revenues collected through the EDR tariff.

Q. WHAT IS THE STANDARD DEFINITION OF MARGINAL COST?

A. As I noted above, the Company agrees with the definition of marginal cost offered by Staff witness Erin O'Neill in her Answer Testimony in Black Hills' EDR proceeding:

> the change in the total cost that arises when the quantity produced is incremented by one unit; that is, it is the cost of producing one more unit of a good. Intuitively, marginal cost at each level of production includes the cost of any additional inputs required to produce the next unit.[29]

The Company agrees with this definition as it describes marginal cost as those that vary with additional levels of production and excludes cost that are fixed and do not vary. In discussing marginal cost, it is important to identify the timeframe that is being analyzed. With respect to an electric utility, the short run marginal costs are the cost to interconnect that customer. However, over the long-term additional fuel, generation, transmission, or distribution capacity may be needed to serve EDR load.

Q. PLEASE EXPLAIN HOW YOU DEFINE "SHORT-TERM" AND "LONG-TERM" MARGINAL COSTS IN YOUR TESTIMONY?

A. For the purpose of my testimony, I refer to "short-term" marginal cost as the initial cost to interconnect the customer including the cost of new generation, transmission, and distribution resources needed to serve the customer. I refer to "long-term" marginal costs as the on-going cost to serve an EDR customer in years one through 10 of the EDR contract. The long-term marginal cost may

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[29] O'Neill Answer Testimony at 22:14-17, Proceeding No. 18A-0791E.

also include the cost of new generation, transmission, and distribution resources that must be built or advanced in order to serve EDR load. In addition, there will be long-term marginal costs associated with fuel, purchased energy, and variable O&M, as well as taxes and corporate overhead. There may also be costs associated with hedging the cost of fuel for EDR customers. Currently the Company does not have any specific plans regarding fuel hedging strategies for EDR customers.

Q. IS PUBLIC SERVICE USING THE DEFINITIONS OF SHORT- AND LONG-TERM MARGINAL COST THE SAME AS STAFF USED IN BLACK HILLS' EDR PROCEEDING?

A. No. Staff witness Erin O'Neill defined short-run marginal cost as the incremental costs to serve EDR customers during the term of the 10-year contract and long-run marginal costs the fully allocated costs including existing infrastructure.[30]

I understand Ms. O'Neill's definitions as they are consistent with the economic theory that suggests that in the long-run, all costs are variable. The definitions that I use are primarily intended to differentiate between costs that are incurred immediately to serve an EDR customer and additional costs that may be incurred during the subsequent term of the contract.

Although Public Service is using different definitions of short and long-term marginal costs in this proceeding, I agree with Staff's general concept surrounding marginal costs. The definitions of short and long-term that I use,

[30] O'Neill Answer Testimony at 23:2-3, Proceeding No. 18A-0791E.

however, really only differentiate between costs that will be addressed through extension policy provisions, and those that will be addressed through on-going bill charges for EDR customers.

Q. HOW DO YOU DEFINE THE MARGINAL COST OF GENERATION CAPACITY?

A. I define the marginal cost of generation capacity as the cost of new generation resources needed to reliably serve an EDR customer during the contract term. It is likely that the short-term marginal generation capacity costs will be zero because the Company is likely to have sufficient generating capacity to serve a new customer. Public Service has a system peak demand of about 6,600 MW, and the addition of a customer under 20 MW is not likely to immediately drive the need for a new power plant nor a new power purchase contract. It is more likely that there will enough excess generation capacity on the system to initially serve the new load. As I discussed in Section VI, if there is not sufficient generation capacity at the time of interconnection, then the EDR customer will be required to fund the full cost of any generation resource specifically acquired to serve their load.

The long-term marginal cost of generation capacity will likely be positive, but timing and magnitude will be uncertain. These costs involve advancing the in-service date or increasing the maximum capacity of a new generation resource. It is possible that an EDR customer would not cause any long-term marginal generation costs during the term of the contract if the Public Service system did not have an incremental capacity need during the 10-year period. But it is more likely that at some point a resource plan will identify the need for new capacity that is at least partially attributable to EDR load.

That said, we anticipate that some large customers may be interested in supplying their new or expanded load through renewable energy options. While Public Service has a suite of renewable energy programming that should be attractive to qualifying EDR customers, we are also proposing a pathway to expand our renewable energy programming to cater specifically to EDR customers. I discuss the procedural path below and Mr. Cowan addresses this in his Direct Testimony as well.

Q. HAS THE COMMISSION PREVIOUSLY ESTABLISHED LONG-TERM MARGINAL COSTS OF GENERATION?

Yes. The recent practice has been to calculate a capacity cost value based on a weighted average of near-term market prices for purchased capacity and the cost of new natural gas peaking generation. This methodology was established in Proceeding No. 13AL-0958E, where the Company proposed new payment rates for Qualifying Facilities ("QF"). The Commission decided the surplus capacity credits were a reasonable measure for capacity costs in years when the Company has no demonstrated capacity need, and then after that the costs of a combustion turbine ("CT") should be used. The Commission noted that a single CT best represents the size and type of forward-looking incremental capacity that the Company is likely to need.[31] This methodology was again used to establish a solar capacity credit for the Company's Renewable*Connect program in Proceeding No. 16A-0055E.

Q. BASED ON THE QF METHODOLOGY WHAT IS THE CURRENT LONG-TERM MARGINAL COST OF GENERATION CAPACITY?

A. The Company most recently updated its QF capacity values in Proceeding No. 19AL-0668E. Table SWW-D-7provides the annual generation capacity values which have a 10 year levelized value of $4.13/kW-month when adjusted for line losses at the primary voltage level.

Table SWW-D-7 – Marginal Generation Capacity Values

2020	$0.99/kW-month
2021	$0.99/kW-month
2022	$0.99/kW-month
2023	$0.99/kW-month
2024	$6.71/kW-month
2025	$6.86/kW-month
2026	$7.01/kW-month
2027	$7.17/kW-month
2028	$7.33/kW-month
2029	$7.48/kW-month

Q. HOW DO YOU DEFINE THE MARGINAL COST OF TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE?

A. I define the marginal cost of transmission and distribution infrastructure to be the cost of additional resources needed to reliably serve an EDR customer during

[31] *See* Commission Decision No. C14-1153, Proceeding No. 13AL-0958E.

their contract term. As I previously explained, the short-term marginal costs of distribution and transmission infrastructure will be assessed to the EDR customer through the modified Distribution Extension Policy and existing Transmission Line Extension Policy. When an EDR customer requests service at a specific location, Company engineers will assess their expected load to ensure that there is sufficient distribution and transmission capacity available to serve that load. To the extent that current capacity is insufficient, the Company will design a line extension or reinforcement to increase the available capacity at the customer's location. Under the Company's proposed modifications to its Distribution Extension Policy for EDR customers, and its existing Transmission Line Extension Policy, they would pay the full cost of any necessary line extensions or reinforcements.[32]

The long-term marginal cost of distribution and transmission infrastructure is the cost of new investments that must be made or advanced due to the existence of an EDR customer in years one through 10 of their EDR contract. After an EDR customer has begun taking service from the Company, it is possible that other load growth in the area will necessitate additional investment in distribution or transmission capacity. However, the existence of an EDR customer may advance the timing of that need, which creates additional system costs.

[32] In Section V, I describe that EDR customers would still be eligible for the off-site distribution line extension credit.

Q. HOW HAS THE COMMISSION PREVIOUSLY ESTABLISHED A METHOD FOR CALCULATING THE LONG-TERM MARGINAL COST OF DISTRIBUTION AND TRANSMISSION CAPACITY?

A. I am not aware of a well-established methodology for determining the long-term marginal cost of distribution and transmission capacity. However, in the 2017-2018 DSM Plan, Proceeding No. 16A-0512EG, the Company provided an analysis of the marginal avoided distribution and transmission cost associated with energy conservation programs ("2016 DSM Study").[33] The 2016 DSM Study compared two scenarios, first a baseline that reflected expected load growth on Public Service's system and then a second scenario that reflected decreased loads from DSM programs. In each scenario, the Company evaluated the distribution and transmission investments necessary to maintain system reliability. The 2016 DSM Study found that decreased load from DSM programs delayed the need for some system investments and created a marginal benefit to the system.

Q. HAS THE COMPANY QUANTIFIED THE LONG-TERM MARGINAL COST OF DISTRIBUTION CAPACITY FOR EDR CUSTOMERS?

A. Yes. Attachment SWW-4 provides the Company's analysis of the long-term marginal cost of distribution and transmission. The analysis followed a methodology similar to that used in the 2016 DSM study. A representative set of 10 substations were selected, consisting of 17 substation transformers and 53

[33] Proceeding No. 17A-0462EG, *see generally* the Direct Testimony of Shawn White, Attachment SMW-6.

existing feeders. These substation sites are located across the service territory in high growth areas where land is available to support prospective new EDR customers. For every year of the 10-year study period (2020 – 2029), one MW of coincident peak load was added to each substation – totaling 10 MW per year and 100 MW over the entire study period. As load was added to the system, transmission and distribution system overloads were monitored, and projects designed to mitigate the overloads. The incremental cost of mitigations was converted into a monthly cost per kW of new load. This monthly cost represents the marginal cost of transmission and distribution capacity to serve new EDR load.

For distribution resources the incremental cost of system investments to support the 100 MW of load growth totals to $44.75 million over the 10-year period. This translates into a revenue requirement of $1.92 per kW month after dividing by the 10 years and the 100 MW load growth. After adjusting for O&M expenditure of seven percent per year, the total cost is $3.50[34] per kW month. This represents the marginal cost of distribution capacity, translated into a monthly rate. Figures SWW-D-3 and SWW-D-4 illustrate the annual long-term marginal cost of distribution in terms of capital investments and revenue requirements, as modeled by the Company.

[34] See Attachment SWW-6.

Figure SWW-D-3
Marginal Distribution Capital Investments

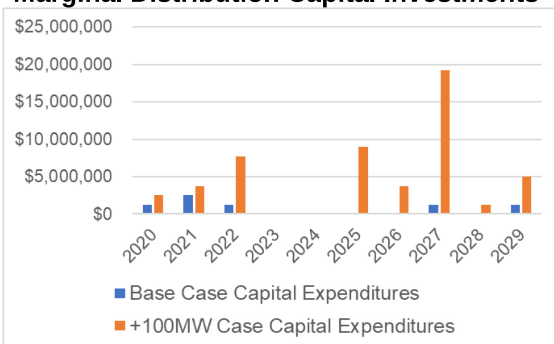
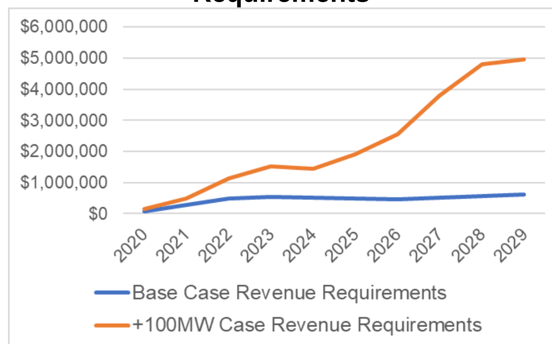


Figure SWW-D-4
Marginal Distribution Revenue Requirements



Q. HAS THE COMPANY QUANTIFIED THE LONG-TERM MARGINAL COST OF TRANSMISSION CAPACITY FOR EDR CUSTOMERS?

A. Yes. The transmission system is typically designed and constructed to handle many years of future load growth. Public Service's Transmission Planning department remains informed of the transmission system's performance through its annual updates to load and generation forecasting, as well as its annual analysis of the system as required by the North American Electric Reliability Corporation ("NERC"). Transmission Planning works to mitigate potential transmission overloads, system constraints, or deficiencies prior to becoming an issue on the transmission system.

The Company performed its analysis on the same 10 substations. The existing load power factor was maintained throughout the study. For example, if the existing power factor was 0.98, then the real power load was increased by one MW and the reactive power was determined based on the existing 0.98

power factor. This was done to assume that the characteristics of the new loads remain similar to the existing loads at the any given substation.

The results of the power flow studies indicate that the addition of 100 MW of load does not adversely impact the transmission system. Further, there were no transmission upgrades attributed to the additional 10 MW at each of the 10 substation locations. The Company's analysis concluded that its existing transmission system and associated facilities are capable of handling incremental load growth and that the long-term marginal cost of transmission resources is zero.

Q. HOW DOES THE COMPANY DEFINE THE MARGINAL COST OF ENERGY?

A. The marginal cost of energy is the expense associated with serving one additional increment of load. With respect to EDR customers, this would be the cost of fuel and purchased power that is needed to serve the increased load. Typically, natural gas units are thought of as the marginal units that stand ready to serve incremental load. However, currently there are many hours, particularly in the off-peak period, when coal plants are the marginal units. Looking forward, the Company has approved plans to phase a number of its coal units out of Public Service's generation fleet, with increasing renewable energy resources coming online – a trajectory we expect to continue in light of the Company and State's aggressive clean energy and emission reduction goals. As renewable resources increase, there will be more situations where there is excess renewable energy on the system and incremental load from EDR customers can be served with that excess generation at little to no incremental cost.

Q. DO YOU MAKE A DISTINCTION BETWEEN SHORT-TERM AND LONG-TERM MARGINAL COSTS OF ENERGY?

A. No. My working definition of short-term marginal costs focuses on the costs needed to interconnect and serve the EDR customers. This concept isn't applicable to energy costs as there are no incremental energy costs needed to interconnect customers. Marginal energy costs will be incurred only once the EDR customer starts receiving power from the Company and will continue throughout the term of the EDR contract.

Q. HOW HAS THE COMMISSION PREVIOUSLY ESTABLISHED MARGINAL ENERGY COSTS?

A. Again, the QF methodology established in Proceeding No. 13AL-0958E is the most salient example of how the Commission has determined the cost for marginal energy. The current practice is to utilize computer simulations of the system dispatch to estimate the marginal cost of energy in each hour. This is how the EDR ECA Factor will be calculated for EDR customers. Each quarter the same computer model that is used for the non-EDR ECA calculation will be used to calculate the marginal, EDR ECA Factor. The hourly marginal cost for each quarter will be weighted by the expected load for EDR customers to derive average on-peak and off-peak charges.

Q. HAS THE COMPANY QUANTIFIED THE MARGINAL COST OF ENERGY?

A. No. Company is not asking the Commission to determine the exact value for marginal energy in this proceeding. Instead we are asking that the Commission find that charging the quarterly EDR ECA Factor to EDR customers ensures compliance with C.R.S. § 40-3-104.3.

Q. WHAT ARE MARGINAL CUSTOMER COSTS?

A. Marginal customer costs are costs such as new meter, meter reading, and incremental billing costs associated with a new EDR customer joining Public Service's system. These costs should not be any different than they are for an existing customer, that is why the Company has specified that the EDR base rate discounts do not apply to EDR customers' monthly S&F charge. This ensures that EDR customers pay for the full marginal customer costs.

Q. HAS THE COMPANY FORECASTED THE MARGINAL COST OF FUEL HEDGING?

A. No. The Company is not proposing to engage in any fuel hedging for EDR customers at this time. To the extent it decides to in the future, it would address the issue through a future filing with the Commission.

Q. WHAT IS THE MARGINAL COST OF CORPORATE SERVICES ASSOCIATED WITH EDR CUSTOMERS?

A. Public Service receives corporate services from Xcel Energy Services ("XES"), such as accounting and IT. For costs that cannot be directly assigned to an operating company, XES will allocate cost based on load or revenues. When an

EDR customer joins Public Service's system, it will cause the allocated share of corporate services to increase.

Q. HAS THE COMPANY ESTIMATED THE MARGINAL COST OF CORPORATE SERVICES?

A. Yes. Corporate services are allocated from XES to Public Service based on total revenue and total energy sales. To estimate the cost of marginal corporate services, the Company modeled a hypothetical EDR customer with $2.8 million in incremental revenue and 70,080 MWh in annual sales volume. Based on the allocation factors from our most recent Phase I proceeding, the results showed that the marginal cost of corporate services is very small, only $0.00016 per kWh.

Q. WHAT ARE THE MARGINAL TAXES AND FEES ASSOCIATED WITH EDR CUSTOMERS?

A. Each municipality assesses a franchise fee or an occupation tax that is included on applicable customers' electric bills. These charges are included on customers' bills and the revenues generated are paid to the municipality. Customer bills also include state sales taxes. These fees will continue to be included in the total bill for EDR customers.

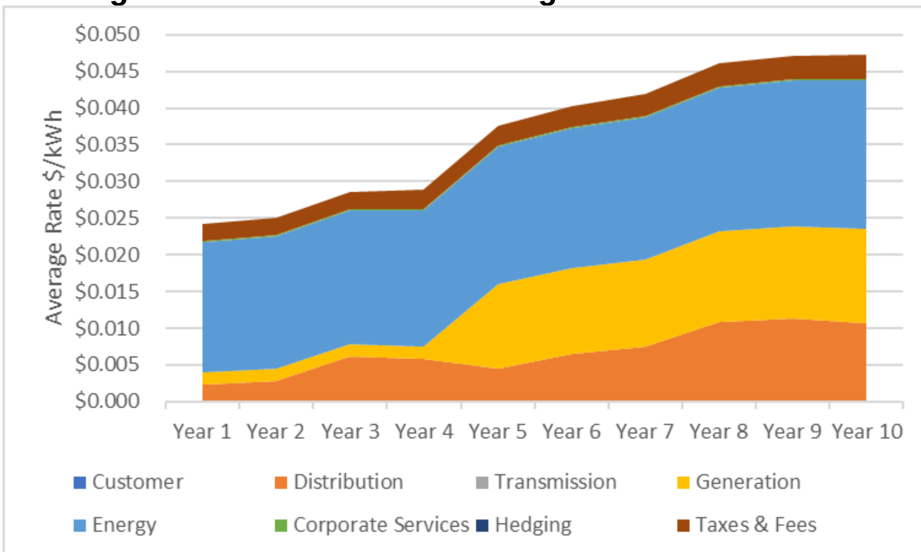
Q. WILL THERE BE ANY MARGINAL DSM COSTS ASSOCIATED WITH EDR CUSTOMERS JOINING PUBLIC SERVICE'S SYSTEM?

A. No, I do not believe so. The Company does not anticipate its conservation goals and program budgets will be impacted by the existence of EDR customers. The current DSM goal of 500 GWh a year was set well above the minimum level required under statute. As such, the addition of an EDR customer would not necessarily increase the Company's DSM goal. Therefore, EDR customers will be paying significant charges associated with DSM but will not be causing any marginal DSM costs, which creates a real benefit for existing customers.

Q. HAVE YOU PREPARED A COMPARISON BETWEEN HOW MUCH EDR CUSTOMERS WILL BE CHARGED VERSUS THE MARGINAL COSTS THEY IMPOSE ON THE SYSTEM?

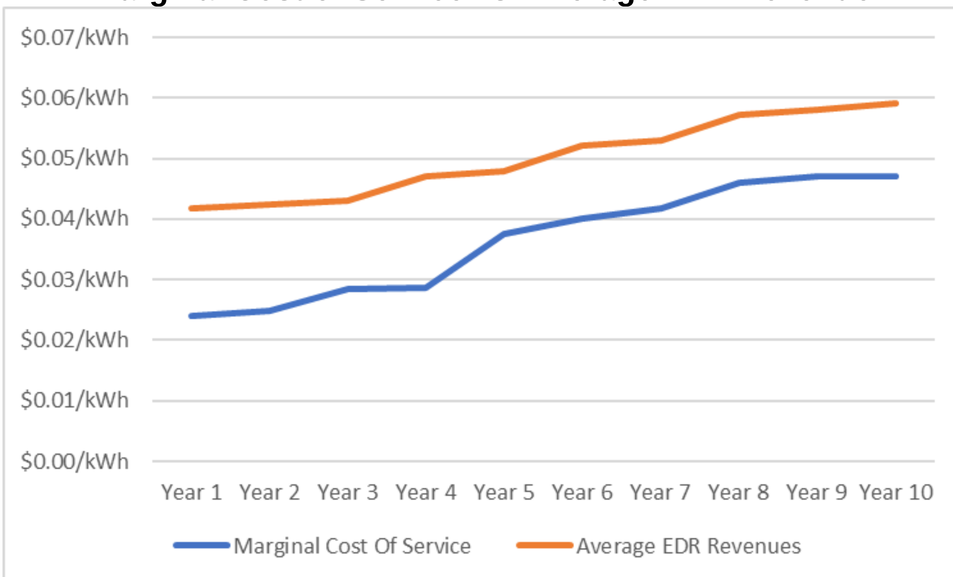
A. Yes, following the definitions I outlined above, I calculated the marginal costs to serve a representative and hypothetical EDR customer taking service under the Primary General tariff (Schedule PG) with 10 MW of peak demand and an annual load factor of 80 percent. I've included this analysis as Attachment SWW-5. Figure SWW-D-5 shows that energy costs are expected to be the largest component of the marginal cost of service. For this forecast, I used the marginal energy costs that were calculated in Proceeding No. 19AL-0668E and escalated them at two percent. As I previously explained, a precise estimate of the future marginal cost of energy in not needed as the EDR ECA Factor that will be charged to EDR customers will be updated on a quarterly basis. The cost of marginal generation and distribution resources are also a significant share of long-term marginal costs. Figure SWW-D-5 below illustrates that these costs are expected to grow in the later years of a 10-year EDR contract.

Figure SWW-D-5– 10 Year Marginal Cost of Service



Overall, the 10-year levelized cost to serve an EDR customer is expected to be 3.5 cents per kWh. In contrast, the 10-year levelized revenues from EDR customers is expected to be 4.9 cents. The difference is the net benefit to customers that will be realized through overall lower rates. Figure SWW-D-6 compares the annual average cost of service to the annual average charge to EDR customers, it shows that in each year the revenues received from EDR customers will exceed the cost of serving them. This ensures that there will be no subsidization of EDR customers, and that the Company’s proposal is consistent with C.R.S. § 40-3-104.3.

Figure SWW-D-6
Marginal Cost of Service vs. Average EDR Revenue



Q. WILL THE MARGINAL COST OF SERVICE AND THE AVERAGE REVENUE SHOWN IN FIGURE SWW-D-6 BE THE SAME FOR EVERY EDR CUSTOMER?

A. No. There may be small variations in the marginal cost to serve customers and the average revenues collected from EDR customers. However, the Company's conservative approach to designing EDR rates creates a wide margin between the two and provides assurance that its EDR tariff is consistent with C.R.S. § 40-3-104.3.

Q. HAVE YOU CONDUCTED ANY SENSITIVITIES ON THE MARGINAL COST ANALYSIS?

A. Yes. I tested to see if load factor would impact the result of the marginal cost analysis and found that although the average marginal cost increases on a

$/kWh basis, the average EDR charges also increase commensurately. Likewise, it will not matter if the customer is a secondary, primary, or transmission level customer, the marginal cost of service will still be below the average EDR rates.

VIII. PROCEDURAL MATTERS RELATED TO EDR

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

A. In this section I describe the Company's proposed process for filing EDR contracts with the Commission. I also discuss the Company's proposed reporting on EDR customers. I conclude this section with a recommendation of how the costs and revenues from EDR customers should be treated in future rate case proceedings.

Q. HOW DOES THE COMPANY PROPOSE TO NOTIFY THE COMMISSION TO ALLOW REVIEW OF CUSTOMERS' STATUTORY ELIGIBLITY TO RECEIVE EDR DISCOUNTS?

A. For Standard EDR Contracts, the Company proposes that once Public Service has determined that a customer qualifies for the EDR tariff, it would file a notice with the Commission that includes the Confidential Standard EDR Contract, customer affidavit confirming eligibility, and the Company's analysis of the customer's eligibility for the EDR discount. I discuss the process for customers enrolling under Non-Standard EDR Contracts in Section X, below.

Q. ONCE A CUSTOMER HAS ENTERED INTO A STANDARD EDR CONTRACT, HOW WILL THAT DOCUMENT BE MADE AVAILABLE TO THE COMMISSION?

A. The Company proposes to make these filings in the Commission's repository proceeding established for the filing of electric service agreements, Proceeding No. 18M-0221E.

Q. WHAT TYPE OF REPORTING IS THE COMPANY PROPOSING FOR EDR CUSTOMERS?

A. The Company proposes to make an annual filing on or before June 1st of each year that provides information on:

- Monthly demand and energy volumes for EDR customers;
- Monthly revenues including contribution to all applicable riders, taxes and fees, from EDR customers;
- A comparison to the revenues that would have been collected under standard rates;
- Information on off-site distribution line extensions that were specifically made for EDR customers; and,
- Summary of all purchased power contracts and short-term purchases for EDR customers, including energy and capacity delivered and contract expenses.

This would apply to all EDR customers, including those who take service in Schedule EDR under Standard and Non-Standard EDR Contracts. As I mentioned above, the annual EDR Report will also include information on off-site distribution line extensions and associated credits that were specifically for EDR customers, and subsequent customers that connect to these line extensions.

Q. WILL THE ANNUAL REPORT INCLUDE THE REASSESSMENT OF THE MARGINAL COST TO SERVE EDR CUSTOMERS?

A. No. Through our conservative approach to designing EDR discounts, the Company seeks to balance statutory compliance with regulatory efficiency. It is unnecessary to recreate the analysis presented in Section VII on an annual basis. Instead, the Company recommends that, like all rates in the Company's electric tariff, the appropriate level of EDR discounts are appropriate for review in future ratemaking proceedings.

Q. HOW DOES THE COMPANY PROPOSE THAT THE COSTS AND REVENUES ASSOCIATED WITH EDR CUSTOMERS BE TREATED IN RATE CASE PROCEEDINGS?

A. C.R.S. § 40-3-104.3 provides that the Commission shall not impute to the utility revenues that would have been received from the qualifying commercial or industrial customer if the customer were being provided service under the corresponding rate for with it would have otherwise qualified under the utility's tariffs. In other words, the Company should not be financially punished for the discounts provided to EDR customers.

I recommend that in the Phase I portion of a rate case proceeding the costs and revenues associated with EDR customers be treated like all costs and revenues, they should be combined with all the other financial information presented in a Phase I proceeding to determine the overall net revenue deficiency. Because the revenues from EDR customers will exceed the cost of serving them, the revenue deficiency will be lower than it would have been absent the existence of EDR customers. There is therefore no need to separately track and report on EDR costs as they are no different than the costs to serve other customers in the context of a Phase I proceeding.

In the Phase II portion of a rate case, the customer counts, monthly peak demands, and total sales quantities associated with EDR customers should be excluded from the class cost allocation analysis. This will ensure that no customer class is allocated additional costs as a result of EDR customers. The revenues from EDR customers should be treated as “other revenues” which will result in lower cost allocation for all customer classes. Typically, other revenue is functionalized using net plant in-service for the various functional categories. The result is that the net revenue requirements for production capacity, transmission, distribution, and other functional categories will all be lowered as a result of the revenue received from EDR customers. This is the same methodology that the Company used for its special contracts in the Company’s 2020 Gas Rate Case Proceeding No. 20AL-0049G.

Q. SHOULD THE COMPANY BE REQUIRED TO KEEP SEPARATE BOOKS AND RECORDS FOR CAPITAL INVESTMENT COSTS ASSOCIATED WITH EDR CUSTOMERS?

A. No. At least not for customers between three and 20 MW taking service under the EDR tariff. Staff recommended Black Hills be required to keep separate books and records in Black Hills’ EDR proceeding, as the means to verify that the proposed EDR rate for a specific large customer was above the marginal cost of service. The Company’s proposal here, which varies from Black Hills’, shows that there will be a large buffer between the EDR customer charges and the marginal cost of service, coupled with our reporting requirements, ensures transparency and eliminates any reason to keep ongoing records of EDR costs.

Q. WHAT WOULD BE THE IMPACT IF THE EDR CUSTOMERS WERE REMOVED FROM THE COMPANY'S PHASE I COST OF SERVICE MODELS?

A. The result would be a larger revenue deficiency and existing Public Service customers would be denied the benefits of the net revenues that EDR customers contribute to the system. This requirement was included in the Commission's Decision in the Black Hills EDR proceeding.[35] While this approach may have been appropriate at the time because the question of marginal cost had not been resolved, here, Public Service has demonstrated that our EDR discounts will be substantially above the marginal cost of service.

[35] *See* Decision No. C19-0446, at ¶ 89.

IX. BENEFITS FROM EDR CUSTOMERS & REVENUE SHARING

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

A. In this section of my testimony, I explain the benefits of new EDR customers joining the Public Service system. I also explain why a revenue sharing mechanism is unnecessary and how it would eliminate incentives for the Company to attract EDR customers to Colorado.

Q. HOW WILL EXISTING PUBLIC SERVICE CUSTOMERS BENEFIT FROM NEW EDR CUSTOMERS JOINING THE SYSTEM?

A. Because the revenues collected from EDR customers will be above the marginal cost of service, the size of the revenue deficiencies in Phase I rate cases will be lower as a result of new EDR customers expanding or locating in our service territory. Lower rate case deficiencies lead to lower overall rates for existing customers and the Company's proposal to treat EDR revenues as "other revenue" in Phase II class cost allocation will result in all customer classes receiving a share of the benefit.

Q. HOW SIZABLE MIGHT THIS BENEFIT BE?

A. From a financial perspective, the size of the benefit will depend on the size and number of EDR customers that join the system. In Section VII, I provided a comparison of the revenues from a representative EDR customer to the marginal cost of service. Assuming a 10 MW customer adds load, the net revenue would be approximately $1 million. It is possible that Public Service will attract multiple

EDR customers, which could decrease rate case deficiencies by several million dollars, again, depending on the total load added.

Q. HOW SIZABLE WOULD THE BENEFIT OF EDR CUSTOMERS BE TO THE COMPANY?

A. Due to Public Service's size, the impact of individual customers is relatively small. Continuing with the example of a 10 MW EDR customer that creates $1 million of net revenue, the impact on the Company's weighted average cost of capital ("WACC") would be approximately 1 basis point. In the spring of this year the Company filed its annual Appendix A that showed in 2019 the electric department had an WACC of 6.07 percent. The addition of a 10 MW EDR customer would have increased the WACC to 6.08 percent. While this isn't a large change, it is meaningful enough to incentivize the Company to actively pursue additional EDR customers.

Q. WHAT WAS STAFF'S RECOMMENDATION IN BLACK HILLS' EDR PROCEEDING REGARDING REVENUE SHARING?

A. Staff recommended that 90 percent of net margins be immediately forfeited back to Black Hills customers. Staff reasoned that Black Hills was only able to offer discounted EDR contracts because other ratepayers have paid for the generation and transmission infrastructure.[36]

[36] *See* Staff's Statement of Position in Proceeding No. 18A-0791E, at p. 22.

Q. HAS THE COMMISSION EVER REQUIRED THE COMPANY TO FORFEIT THE REVENUES ASSOCIATED WITH A NEW C&I CUSTOMER?

A. No. The revenues from new customers has always served to decrease net revenue deficiencies and delay the need for rate cases. There is no precedent that I am aware of for denying the Company this revenue.

Q. WHAT WOULD BE THE IMPACT OF REQUIRING THE COMPANY TO FORFEIT EDR NET REVENUE PRIOR TO THE COMPANY'S NEXT RATE CASE?

A. This would eliminate the incentive for the Company to pursue EDR customers. Instead of allowing the utility to receive a short-term benefit from new EDR customers until its next rate case when the benefit is shared with all customers, Staff's revenue sharing proposal would all but eliminate the incentive for the Company to pursue these customers. Providing the Company no incentive to pursue EDR customers would run directly contrary to the purpose of the EDR and HB 18-1271, which is designed to promote economic development by creating jobs, increasing tax base, and benefit existing ratepayers throughout the State.

Q. UNDER STAFF'S PROPOSAL FROM THE BLACK HILLS' PROCEEDING, WOULD THE COMPANY BE REQUIRED TO FORFEIT 90 PERCENT OF NET EDR REVENUE EVEN IF IT WAS EARNING LESS THAN ITS AUTHORIZED RETURN?

A. Yes. Staff's proposal did not include any provision that eliminated the 90 percent sharing in the event that Black Hills was earning less than its authorized rate of return. It would be inequitable to deny Public Service revenues that have traditionally accrued to the utility, particularly when the EDR is designed to stimulate economic growth, and in years when the Company is financially lagging.

Q. WOULD THE COMPANY CONSIDER WITHDRAWING ITS APPLICATION IF THERE IS NO INCENTIVE TO THE COMPANY TO PURSUE EDR CUSTOMERS?

A. Yes. As explained in the Application, Public Service's EDR proposal, while brought pursuant to Colorado law, is voluntary. Thus, to the extent the Commission modifies Public Service's proposal in a manner Public Service finds unacceptable, Public Service requests the final order make clear that the Company maintains discretion as to whether it implements the EDR proposals and related tariff modifications that are authorized as a result of this Application proceeding. Accordingly, Public Service is requesting that the Commission's order authorize, but not require, any of the compliance advice letter filing(s) that would be needed to implement the EDR tariff authorized as part of this Application proceeding.

X. APPLICATIONS FOR APPROVAL OF NON-STANDARD EDR CONTRACTS AND EXPANSIONS OF VOLUNTARY RENEWABLE ENERGY PROGRAMS TO ACCOMMODATE EDR CUSTOMERS

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

A. In this section, I present Public Service's request to establish an expedited process for the Commission to address Non-Standard EDR Contracts and requests to expand voluntary renewable programs to accommodate EDR customers pursuant to C.R.S. § 40-3-104.3(6)(d).

Q. WHY IS PUBLIC SERVICE REQUESTING AN EXPEDITED PROCESS FOR THESE CATEGORIES OF PROCEEDINGS?

A. As explained by Ms. Velasquez-Horvath in her Direct Testimony, we expect that the amount of time it could otherwise take to obtain a final Commission decision on these Non-Standard Contracts or renewable energy program expansions through the typical procedural timeline, which can take an upwards 280 days from the date of filing to reach a final determination, would be a significant deterrent for many prospective EDR customers. Being able to obtain a Commission determination on requests to approve Non-Standard EDR Contracts and requests to expand existing voluntary renewable programs to accommodate EDR customers in an expedited manner through a pre-established procedural framework will enable us to provide the level of responsiveness and predictability large customers demand when navigating the critical and often time-sensitive decision of whether to locate new or expand existing operations in Colorado.

Q. WHY IS PUBLIC SERVICE PROPOSING THE SAME PROCEDURAL FRAMEWORK FOR BOTH TYPES OF REQUESTS?

A. Prospective EDR customers will benefit from the same expedited procedural framework being used to address both categories of requests as they are often complementary in nature. For example, it would make little sense to proceed with a requested expansion of a voluntary renewable energy program to accommodate an EDR customer unless that EDR customer's EDR contract is approved; otherwise, there would be no EDR customer to accommodate. As explained in Ms. Velasquez Horvath's Direct Testimony, the Company also expects that the availability of voluntary renewable energy programs will be an important factor for many prospective EDR customers' decision-making process about whether to choose Colorado. We expect that some prospective EDR customers may have such a strong commitment to their renewable energy goals that they may condition their EDR contract commitments and willingness to move forward on the availability of such programs. Additionally, Public Service expects that in some instances, we may need to request expansion of a voluntary renewable program in conjunction with a Non-Standard EDR Contract. Handling both requests in the same proceeding and/or under the same procedural timeline will be a more efficient use of all parties' resources, including the Commission's, than addressing these related requests through separate proceedings or procedural schedules.

Q. PLEASE DESCRIBE THE PROCEDURAL FRAMEWORK PUBLIC SERVICE IS PROPOSING TO ADDRESS THESE REQUESTS.

A. Public Service proposes that the Commission approve such applications within 120 days after deeming them complete, consistent with HB 18-1271. Such a procedural framework to address future applications to approve Non-Standard EDR Contracts and applications to expand existing voluntary renewable energy programs to accommodate EDR customers could work as follows:[37]

- **Day 1:** Public Service files an application, supported by an affidavit or supporting testimony requesting approval of a Non-Standard EDR Contract and/or requesting to expand voluntary renewable energy program(s) to accommodate EDR customer(s).
- **Day 15:** Intervention deadline.
- **Day 30:** Decision on permissive interventions and decision on completeness of application.
- **Day 60:** Answer testimony filed (if requested/needed).
- **Day 75:** Rebuttal/Cross-Answer testimony filed (if requested/needed).
- **Day 90:** Hearing (if requested/needed), with deadlines for Statements of Position to be set on a case-by-case basis.
- **Day 150:** Commission Decision.

The Company understands that exact timing of an individual application may need to be adjusted to accommodate the Commission and intervening

[37] This is a general schedule and additional deadlines or accommodations may be built into this framework to accommodate weekends and holidays, and other typical procedural deadlines included in procedural schedules, such as pre-hearing motions, corrections, and settlements.

parties, but the Company is requesting that the Commission make a finding in this proceeding that a Commission decision within 120 days after deeming such applications complete is in the public interest and consistent with the legislative objectives of HB 18-1271.

Q. WHY DOES PUBLIC SERVICE REFER TO THIS THIS PROCEDURAL FRAMEWORK AS "EXPEDITED?"

A. This timing is consistent with the default statutory timeline for the Commission to consider applications under C.R.S. § 40-6-109.5(1), as well as the timing contemplated in C.R.S. § 40-3-104.3 for the determination of voluntary renewable energy programs to accommodate EDR customers. The reason we are referring to this procedural framework as "expedited" is that the Commission often determines that more time is required to determine applications and adds an additional 130 days to the default statutory deadline pursuant to C.R.S. § 40-6-109.5 (1), and our proposed procedural framework does not incorporate this additional time.

Q. WHY DOES PUBLIC SERVICE BELIEVE THIS PROCEDURAL FRAMEWORK IS APPROPRIATE TO ADDRESS REQUESTS TO EXPAND VOLUNTARY RNEWABLE ENERGY PROGRAMS TO ACCOMMODATE EDR CUSTOMERS?

A. The expedited procedural framework is appropriate to address requests to expand existing voluntary renewable energy programs to accommodate EDR customers given the time-sensitive nature of EDR opportunities. It is also reasonable because the underlying programs have already been approved by the Commission, meaning there will be fewer issues to decide. The Company will not propose any material structural changes to existing voluntary renewable programs that could negatively impact other customers who participate in these programs.

Q. WHY IS THIS PROCEDURAL FRAMEWORK ALSO APPROPRIATE TO ADDRESS APPLICATIONS TO APPROVE NON-STANDARD EDR CONTRACTS?

A. This procedural framework is also appropriate to address applications to approve Non-Standard EDR Contracts, including those for customers adding over 20 MW of load, due to the time-sensitive nature of these opportunities and customers' need for predictability in navigating the Commission approval process. The Company is confident that Commission endorsement of an expedited process will enhance the attractiveness of Colorado to customers for whom electricity cost is a major consideration in choosing where to locate or expand operations.

Q. DOES THE COMPANY HAVE SIMILAR PROCEDURAL FRAMEWORKS IN PLACE FOR OTHER TIME-SENSITIVE COMMISSION REQUESTS?

A. Yes. In the Company's Innovative Clean Technology Program ("ICT"), in Decision No. 09C-0889, Proceeding No. 09A-015E, the Commission granted the Company's request to handle ICT project applications in the most expedited manner, under the 120-day statutory timetable set forth in § 40-6-109, C.R.S.[38] As stated in this decision, the Commission found that an expedited schedule required the following:

> We also find that an expedited schedule will require condensing many aspects of the schedule, including a shortening of the notice and intervention period. We find that any ICT project application requesting expedited processing needs to include a request for shortened notice and intervention period. We further direct Public Service to discuss a proposed procedural schedule with stakeholders and include in the application stakeholder comments on the proposed procedural schedule.[39]

Q. HAS THE COMMISSION APPROVED ICT PROJECT APPLICATIONS USING THIS EXPEDITED FRAMEWORK?

A. Yes, the Commission has consistently approved several ICT Applications in approximately 90-150 days.[40]

Q. WHAT DOES PUBLIC SERVICE PROPOSE SHOULD BE INCLUDED IN AN APPLICATION FILING FOR APPROVAL OF A NON-STANDARD EDR CONTRACT?

A. The Company will offer an affidavit demonstrating the prospective EDR customer's statutory eligibility for an EDR discount (as discussed by Ms. Velasquez Horvath), file the Non-Standard EDR Contract on a confidential or highly confidential basis (and with a motion for extraordinary protection, as

[38] Decision No. 09C-0889, at ¶ 42, Proceeding 09A-015E.
[39] Decision No. 09C-0889, at ¶ 42, Proceeding 09A-015E.
[40] Cameo ICT Application, Proceeding No. 09A-015E, was filed on January 14, 2009 and granted on May 4, 2009 by Decision No. C09-0472; C09-0472; the Solar Battery ICT Application was filed on August 25, 2011, in Proceeding No. 11A-731E, and granted by Decision No. C11-1256 on November 23, 2011; Stapleton and Panasonic ICT Application, Proceeding No. 15A-0847E was filed on October 29, 2015 and settlement was granted on March 21, 2016 by Decision No. C16-0196.

applicable). With its Application, the Company will demonstrate, through testimony or a sworn affidavit, that the prospective EDR customer will cover the Company's marginal cost to serve the prospective EDR customer and that there will be no prohibited subsidization under C.R.S. § 40-3-104.3. The Company would also incorporate any request to expand an existing voluntary renewable energy program to accommodate the EDR customer. The Non-Standard EDR Contract will reflect the discount offered, either in the form of a specific $/kW base rate charge or percent discount to standard rates. Through such applications, Public Service would request that the Commission find the Non-Standard EDR Contract in compliance with C.R.S. § 40-3-104.3, as well as approval for any expansion of an existing voluntary renewable energy program to accommodate the EDR customer as applicable.

Q. HOW DOES THE COMPANY ANTICIPATE IT WILL DEMONSTRATE THAT THE PROSPECTIVE CUSTOMER WILL COVER THE COMPANY'S MARGINAL COST TO SERVE THEM UNDER THE NON-STANDARD EDR CONTRACT?

A. The Company plans to apply the same marginal cost definitions included in its illustrative EDR tariff, and as I outlined above, to all EDR contracts – including its Non-Standard EDR Contracts. We anticipate the same cost adjustments would also apply to Non-Standard EDR customers, including the same marginal cost EDR ECA Factor and full-cost, EDR DSMCA.

XI. REQUEST TO DEFER EDR APPLICATION PROCEEDING EXPENSES

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

A. In this section of my testimony, I support the Company's request to defer expenses associated with pursuing this Application.

Q. IS PUBLIC SERVICE INCURRING EXPENSES TO PREPARE THIS APPLICATION FILING AND LITIGATE THIS PROCEEDING?

A. Yes. Public Service has already incurred expenses to prepare the case filing and will continue to incur expenses to perform the other tasks attendant to filing and litigating this proceeding before the Commission.

Q. IS PUBLIC SERVICE PROPOSING TO RECOVER THESE EXPENSES IN THIS EDR APPLICATION PROCEEDING?

A. No, the Company requests the Commission defer the review, approval, and recovery of these expenses to the next Phase I electric rate case. Specifically, EDR case expenses would be deferred into a regulatory asset without interest until they are presented for cost recovery in the next Phase I electric rate case. The Company commits to presenting actual EDR expenses at the time of that filing.

Q. WHY IS IT APPROPRIATE FOR PUBLIC SERVICE TO INCLUDE EDR APPLICATION PROCEEDING EXPENSES AS A RECOVERABLE ITEM IN THE COST OF SERVICE?

A. Most businesses have the flexibility to set their prices based on their assessment of the market and the demand for their products. Utilities that are subject to cost of service regulation do not have this same flexibility, but rather must make rate filings and obtain public utility commission authorization to establish new rates like the proposed EDR tariff discounts. Accordingly, it is my understanding that it has been the long-standing practice of this Commission to treat reasonable expenses of cost recovery and other rate case proceedings as a necessary cost of doing business and, after review, to allow recovery of such expenses through mechanisms established in a rate case proceeding.

Q. WHAT AMOUNT OF EXPENSE DOES PUBLIC SERVICE EXPECT TO INCUR IN THIS APPLICATION PROCEEDING?

A. The total expenses associated with this filing are estimated to be $319,990, assuming a fully litigated case.

Q. PLEASE LIST AND GENERALLY DESCRIBE THE MAJOR EXPENSE CATEGORIES YOU EXPECT THE COMPANY TO INCUR RELATED TO THIS FILING.

A. The major categories of expenses include the following:

- <u>Hearing Costs:</u> During the course of the proceeding, a court reporter may be necessary to transcribe depositions and hearings before the Commission or administrative law judge. There is a cost for the court reporters to record and then transcribe these proceedings. This fee increases or decreases based upon the length of the transcript and the timeframe in which the reporter must turn over the transcript.

- Legal Counsel: The Company does not staff its legal department assuming continuous ongoing rate filings. Additionally, the expertise to file a comprehensive case is not always in-house for all topics; thus, outside legal assistance is necessary. Therefore, outside legal assistance in developing, processing, and litigating a case is a valid expense.

- Customer Noticing: While the Company is not seeking express approval of rate changes through an Advice Letter filing *via* its Application in this proceeding and Rule 1207 does not directly apply to this proceeding, it is providing notice of its filing through various channels described in the Application to ensure that customers have an opportunity to weigh in on the filing. These channels include the formal notice provided by the Commission, posting of notice through the Company's website, email communication to C&I customers, and providing newspaper notice of this filing. Noticing costs for this filing include costs to execute these actions.

Q. HOW DO THESE COST CATEGORIES TRANSLATE INTO THE TOTAL ESTIMATED EDR APPLICATION PROCEEDING EXPENSES?

A. Table SWW-D-8 below lists the categories of expenses described above and the total cost estimate for each category.

Table SWW-D-8: EDR Application Proceeding Expenses by Category

Category	Expense Estimate
Hearing Costs	$9,500
Legal Counsel	$300,000
Customer Noticing	$10,490
Total	$319,990

Q. ARE THE COSTS DESCRIBED ABOVE REASONABLE?

A. Yes. The largest portion of estimated expenses are associated with outside legal counsel. As I discussed above, the Company retains outside legal counsel because the Company does not staff for continuous ongoing rate proceedings. In this case, we retained a firm with rate proposal expertise and specific knowledge of Public Service and other Xcel Energy operating companies. The firm has provided, or will provide, assistance in assembling testimony and attachments, witness preparation, advice on strategy, responding to discovery, and generally processing the case. I would also add that the Company's internal legal team works hard to ensure that duties are appropriately assigned to outside legal counsel and to ensure that work efforts are not duplicative. The internal and external legal teams work as a unit and are in constant coordination to be as efficient as possible.

XII. SUMMARY OF RECOMMENDATIONS AND CONCLUSION

Q. COULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A. Yes, in sum, I recommend that the Commission approve Public Service's Economic Development Rate proposal, finding it reasonable, in the public interest, and consistent with HB 18-1271, consistent with the discussion and recommendations above and in the Company's Application and Direct Case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Statement of Qualifications

Steven W. Wishart

I began my employment with Xcel Energy Services, Inc. in 2005, in the Company's Demand-Side Management department. I am currently the Director of the Public Service Pricing and Planning team. My responsibilities include quantitative analyses, cost allocation, and rate design, and policy support on a number of Colorado regulatory issues.

Prior to taking my current position, I worked for Xcel Energy Services Inc. in Minneapolis, Minnesota, as Director of Resource Planning and Bidding for the Northern States Power region. In that role, I oversaw resource planning and resource acquisition processes for that company.

From 2009 through 2012, I worked for the Company as the Manager of Quantitative Analytics. In that role, I managed a group responsible for conducting long-term analyses of the costs and performance of Xcel's electric generating systems.

Prior to joining Xcel Energy in 2005, I was a PhD candidate in the Department of Applied Economics at the University of Minnesota where I studied energy related topics.

**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 AN ECONOMIC DEVELOPMENT RATE PROPOSAL PURSUANT TO COLORADO HB 18-1271	))))))	**PROCEEDING NO. 20A-XXXXE**

**AFFIDAVIT OF STEVEN W. WISHART
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO**

I, Steven W. Wishart, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this 21 day of August, 2020.

Steve Wishart
Steven W. Wishart
Director, Pricing and Planning

Subscribed and sworn to before me this 21st day of August, 2020.

Dawn Moffit
Notary Public

My Commission expires 4-22-2024

DAWN MOFFIT
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20084013859
MY COMMISSION EXPIRES APRIL 22, 2024