

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

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

**DIRECT TESTIMONY OF GERALD STELLERN
ON
BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO**

October 31, 2011

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DIRECT TESTIMONY OF GERALD STELLERN

1 **I. INTRODUCTION AND QUALIFICATIONS**

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

3 A. My name is Gerald Stellern. My business address is 1800 Larimer Street, 6th
4 floor, Denver, Colorado 80202.

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

6 A. I am employed by Public Service Company of Colorado (“Public Service” or
7 “Company”). My title is Manager of Transmission Assessment Management
8 (“TAM”).

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

10 A. I am testifying on behalf of Public Service Company of Colorado (“Public
11 Service” or the “Company”).

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

14 A. Yes. A description of my qualifications, duties, and responsibilities is included
15 as Attachment A.

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

2 A. The purpose of my testimony is to discuss an overview of Public Service's
3 transmission system, to present the transmission facilities to be constructed in
4 the 2012-2016 time period, and to summarize the transmission injection
5 capability on the Public Service system. I will also discuss two transmission
6 studies required to be submitted with the 2011 Electric Resource Plan ("2011
7 ERP") under Colorado Public Utilities Commission ("CPUC") Decision No.
8 C10-1328, in the Clean Air-Clean Jobs Act Docket ("CACJA"). These studies
9 were the 10-12 year study of the Denver Boulder load serving area and the
10 Cherokee 4 replacement study.

11 **Q. PLEASE DESCRIBE THE PUBLIC SERVICE TRANSMISSION SYSTEM.**

12 A. Public Service owns and maintains approximately 4,360 circuit-miles of
13 transmission lines, all located inside Colorado. The transmission lines are
14 rated 44kV, 69 kV, 115 kV, 138 kV, 230 kV, and 345 kV. The Company also
15 uses 223 transmission and distribution substations to deliver electric energy
16 to 1.4 million customers in Colorado. Public Service's transmission network
17 runs primarily along the Front Range of Colorado; however, we utilize
18 transmission across the entire state to bring generation resources to our load
19 centers to serve load. The Public Service territory includes the Denver-
20 Boulder metro area, as well as the I-70 corridor to Grand Junction, the San
21 Luis Valley, Greeley, Sterling, and Brush. Public Service also serves the
22 following wholesale customers: Holy Cross Energy, Yampa Valley Electric
23 Association, Grand Valley Rural Power Lines, Intermountain Rural Electric

1 Association, the Town of Center, and the City of Burlington. The neighboring
2 transmission systems connected to Public Service include: Arkansas River
3 Power Authority, Black Hills Energy, Colorado Springs Utilities (“CSU”), Platte
4 River Power Authority (“PRPA”), Tri-State, and the Western Area Power
5 Administration (“Western”).

6 **Q. CAN YOU DESCRIBE THE SUB-REGIONAL LONG TERM PROCESSES IN**
7 **THE STATE OF COLORADO?**

8 A. All of the Transmission Providers in Colorado belong to a sub-regional
9 transmission planning group known as the Colorado Coordinated Planning
10 Group (CCPG). CCPG is a planning forum that operates to assure a high
11 degree of reliability in joint planning, development and operation of the high
12 voltage transmission in the Rocky Mountain Region. The group meets on a
13 regular basis to discuss coordinated transmission planning in an open
14 stakeholder process. CCPG Transmission providers are currently working on
15 developing a coordinated 10 year transmission plan for the state of Colorado
16 that will be submitted Feb 1, 2012 to the Commission. Significant stakeholder
17 outreach concerning the 10 year plan is also taking place and will be included
18 in the February 1, 2012 filing. The CCPG also has a work group that is
19 evaluating a 20 year conceptual plan through regular meetings in an open
20 stakeholder process.

21 **Q. PLEASE DESCRIBE HOW THE PUBLIC SERVICE LONG-TERM**
22 **TRANSMISSION PROCESS AND PROJECTS ARE COMMUNICATED TO**
23 **INDIVIDUAL STAKEHOLDERS.**

1 A. Public Service annually develops a 10-year transmission plan based on
2 current load forecasts, current resource plans, and updates from the
3 transmission providers in the WECC and the Colorado Coordinated Planning
4 group ("CCPG"). The plan is routinely communicated to stakeholders through
5 meetings held throughout the year with the sub-regional group WestConnect,
6 CCPG, and Public Service's FERC 890 stakeholder meetings.

7 **Q. PLEASE DESCRIBE THE WORK THAT THE PUBLIC SERVICE TAM**
8 **GROUP DID IN ASSESSING THE GENERATION CAPACITY THAT COULD**
9 **POTENTIALLY BE ADDED TO THE PUBLIC SERVICE TRANSMISSION**
10 **SYSTEM (TRANSMISSION INJECTION CAPABILITY)?**

11 A. The Public Service TAM group routinely performs feasibility studies and
12 system impact studies for Large Generator Interconnect Agreement ("LGIA")
13 requests. These are associated with the FERC process and the Public
14 Service Open Access Transmission Tariff ("OATT"). The results of these
15 studies determine the cost, the time to construct, and the feasibility to add
16 generation to the transmission system. These studies are conducted on a
17 stand-alone basis with no other queued generation requests considered. The
18 Company also performs other transmission studies for purposes of
19 transmission planning as part of the routine 10 year planning, capital budget
20 process, and NERC reliability assessments. The results of those technical
21 studies and planning experience were factors in developing the approximate
22 amount of potential generation injection on the Public Service transmission
23 system.

1 **Q. WHAT ARE THE GENERAL FINDINGS OF THE TRANSMISSION**
2 **INJECTION CAPABILITY STUDIES STATED IN TABLE 2.5-3 (VOLUME**
3 **2)?**

4 A. Table 2.5-3 illustrates the potential amount of generation that could be
5 interconnected to the Public Service transmission system on a stand-alone
6 basis. The feasibility of new generation interconnected to the transmission
7 system will be verified in the FERC Large Generator Interconnection
8 Agreement ("LGIA") process.

9 **Q. DID THE PUBLIC SERVICE TAM GROUP PERFORM A TRANSMISSION**
10 **STUDY TO EVALUATE THE NEED FOR THE INDEPENDENT POWER**
11 **PRODUCER ("IPP") GENERATION IN THE GREELEY AREA TO**
12 **MAINTAIN TRANSMISSION RELIABILITY?**

13 A. Yes. Public Service has performed a detailed transmission study to analyze
14 the effects to the Foothills/Greeley area transmission system upon the
15 termination of the Thermo Monfort Purchased Power Agreement ("PPA") (32
16 MW which expired on 6/30/2011) and Thermo Power and Energy (UNC-
17 Greeley) PPA (69 MW which will expire on 8/31/2013) with the assumption
18 that the Company would no longer have access to those generation facilities
19 upon PPA expiration. These studies took into consideration the three
20 reliability projects that are currently in the Public Service capital budget, and
21 planned to be in service before the expiration of the UNC-Greeley PPA. The
22 projects include the installation of a third 230/115 kV transformer at the Weld
23 Substation, the conversion of the Godfrey Switching Station to a Breaker

1 Station, and the addition of a 25MVAR Capacitor Bank at Monfort Substation.
2 It was determined that under N-0 system intact conditions, the transmission
3 system in the Greeley area has adequate reliability without these generation
4 resources. Transmission reliability was also adequate for N-1 contingencies
5 during the summer peak conditions. We conclude, therefore, that there is not
6 a transmission system reliability need to renew those PPAs.

7 **Q. DID THE PUBLIC SERVICE TAM GROUP PERFORM A 10-12 YEAR**
8 **TRANSMISSION STUDY OF THE DENVER-BOULDER LOAD SERVING**
9 **AREA AFTER SOLICITING INPUT FROM THE CPUC STAFF?**

10 A. Yes.

11 **Q. PLEASE DESCRIBE THE PROCESS OF SOLICITING INPUT FROM THE**
12 **CPUC STAFF.**

13 A. Public Service met with the CPUC Staff late in 2010 to discuss the scope of
14 work for the report, the base cases to be used, and the relationship to Table 5
15 of Exhibit TWG-1 in the CACJA docket. In early 2011, Public Service and
16 Staff met again and discussed a written scope of work upon which the study
17 would be based. Public Service and Staff met to discuss the draft report that
18 was based on the developed scope. Public Service solicited input from Staff
19 throughout the study, which was incorporated in the final report.

20 **Q. WHAT WAS THE PURPOSE OF THE STUDY?**

21 A. The purpose of the study was to review the Denver-Boulder load serving
22 Network in the year 2022 to evaluate overloads on Table 5 of Exhibit TWG-1
23 in the CACJA docket. (Table 5 titled "2018 Contingency loading results")

1 evaluated different scenarios of generation levels at Cherokee with
2 transmission contingencies.

3 **Q. PLEASE SUMMARIZE THE RESULTS OF THE 10-12 YEAR**
4 **TRANSMISSION PLANNING STUDY.**

5 A, The study results indicate thermal overloads of 14 transmission facilities in
6 the Denver-Boulder metro area. The majority of these overloads occur in the
7 unlikely scenario of no generation available at Cherokee, Arapahoe and
8 Valmont during a summer peak day and a transmission element concurrently
9 forced out of service (N-1). The study also identified transmission system
10 reinforcements necessary to ensure that the Denver-Boulder metro area
11 transmission facilities have adequate thermal capability to achieve reliable
12 operation over the entire range of Cherokee generation dispatch levels from
13 922 MW to 0 MW. Several of these overloads can be mitigated by redispatch
14 of generation in the Denver-Boulder metro area. This 2022 transmission
15 planning study gives Public Service a look ahead into potential thermal
16 constraints and system conditions that must be monitored in future
17 transmission studies.

18 **Q. PLEASE DESCRIBE THE TRANSMISSION STUDY TO EVALUATE**
19 **ALTERNATIVES TO CHEROKEE 4.**

20 A. Based on CPUC Decision No. C10-1328, Public Service developed a
21 Transmission Planning study (Year 2022) for Cherokee 4 replacement
22 alternatives ("Cherokee 4 Study"). The Public Service Transmission group
23 with input from the Resource Planning Group developed three alternatives to

1 Cherokee 4. The three alternatives to Cherokee 4 were: (a) new generation
2 at Cherokee, (b) IPP generation at Arapahoe, Valmont and Fountain Valley,
3 and (c) renewable resources outside the metro area (delivered to the
4 Comanche area).

5 **Q. PLEASE SUMMARIZE THE RESULTS OF THE CHEROKEE 4 STUDY?**

6 A. The steady-state contingency analysis results in the study indicate that
7 transmission reinforcements and/or improvements are needed for all three
8 alternatives in order to achieve adequate transmission system reliability. The
9 reactive margin analysis results in the study indicate that all three alternatives
10 satisfy the WECC system voltage stability criteria at all three monitored
11 stations in the Denver metro area. However, the highest reactive margins
12 occur with replacement generation located at Cherokee, which suggests that
13 alternative (a) above is more robust compared to alternatives (b) and (c) to
14 minimize the risk of voltage collapse in the Denver metro area. This long-
15 term planning horizon (year 2022) study gives Public Service a look ahead
16 into potential thermal constraints that could occur for each Cherokee 4
17 replacement alternative if the summer peak load forecasted for year 2022 is
18 realized. Per prudent transmission planning practice, Public Service will re-
19 evaluate and re-validate the Cherokee 4 Study results in future near-term (5-7
20 year) planning horizon studies when the system loads and resources can be
21 modeled with more certainty. All transmission reinforcements identified in this
22 study can be normally implemented within a 3-5 year lead time. We believe
23 we would have sufficient time to remedy any transmission concerns based on

1 the outcome of Phase 2 of this docket, which could result in removal of
2 Cherokee 4 from service completely.

3 **Q. DID THE COMPANY ALSO PERFORM ADDITIONAL TRANSMISSION**
4 **STUDIES FOR THE ARAPAHOE SITE?**

5 A. No. However, the Cherokee 4 study indicates that although there is value in
6 retaining the existing generation at Arapahoe to provide operational flexibility
7 by allowing utilization of generation dispatch (Arapahoe) to mitigate
8 contingency thermal overloads, it is not essential to retain this generation for
9 ensuring transmission system reliability. Like the potential closure of
10 Cherokee 4, we believe we would have sufficient time to remedy any
11 transmission system concerns, if Arapahoe 4 were retired based on the
12 outcome of Phase 2 of this docket.

13 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

14 A. Yes, it does.

Gerald Stellern

Statement of Qualifications

I started my career at Public Service Company of Colorado (“Public Service”) in 1974. My career started in the Electric Planning and Analysis group where I worked for approximately 15 years working as a Transmission Planning Engineer, and later as the Supervisor of Loads and Resources Planning. My job function was primarily to produce a customer demand load forecast and to acquire adequate resources to meet that customer demand. I received my Professional Engineer’s license from the State of Colorado in 1978.

In 1990 my career directed me to Operations and the Operations Control Center. I worked as Senior Operations Engineer, Manager of the Transmission and Substation desk, Operations Manager, and Manager of the Real Time Engineering group. In this capacity, I performed all functions related to managing and operating the Transmission assets of Public Service and the interconnected Transmission system.

In 2005, I became the Manager of Transmission Assessment Management for Public Service, in which I have a highly qualified team of eight Transmission planning engineers who I work with to perform technical studies and evaluation of Public Service’s transmission assets. The TAM group is responsible for the 5 year capital transmission budget as well as planning the Transmission system of Public Service to meet the growing needs of our customers and to ensure reliability. A large portion of our work is compliance with the NERC reliability standards: as such

PSCo TAM performs an annual assessment of the transmission assets to verify full compliance with the standards. Transmission Asset Management is also responsible for the future development of Transmission plans under the SB-07-100 process and for performing Feasibility Studies and System Impact studies for generation interconnection requests under the FERC Large Generator Interconnection Agreement (LGIA) process.