BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2011 ELECTRIC RESOURCE PLAN	))))	**DOCKET NO. 11A-869E**
IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE ACQUISITION OF THE BRUSH 1, 3, AND 4 GENERATION FACILITIES AND IN CONNECTION THEREWITH THE GRANT OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY IF REQUIRED AND THE APPROVAL OF COST RECOVERY THROUGH A GENERAL RATE SCHEDULE ADJUSTMENT	))))))))))	**DOCKET NO. 12A-782E**
IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF THE POWER PURCHASE AGREEMENT FOR 118.8 MW OF NATURAL GAS GENERATION, EARLY RETIREMENT OF ARAPAHOE UNIT 4, AND A GAS SALES AGREEMENT.	)))))))	**DOCKET NO. 12A-785E**

SUPPLEMENTAL REBUTTAL TESTIMONY AND EXHIBITS OF CURTIS DALLINGER

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 5, 2012

LIST OF EXHIBITS

Exhibit No. CD-2	CIG Firm Transport-storage analysis
Exhibit No. CD-3	CIG Mainline Total Annual Firm Reservation Revenue
Exhibit No. CD-4	CIG Contract renewal savings

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Curtis Dallinger. My business address is 1800 Larimer St, Denver, CO 80202.

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

A. I am employed by Xcel Energy Services, Inc., a wholly-owned subsidiary of Xcel Energy Inc., the parent company of Public Service Company of Colorado ("Public Service or "Company"). My job title is Director, Gas Resource Planning.

Q. DID YOU FILE TESTIMONY IN THIS DOCKET?

A. Yes, I filed both direct and rebuttal testimony in this docket

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I address Staff witness Ms. Podein's suggestion that it may not be appropriate to consider the savings to customers from the Gas Sales Agreement between Public Service and Southwest Generation because Staff in the future may have concerns about the recovery of the cost of the underlying transport agreement that Public Service has with Colorado Interstate Gas Company ("CIG") that facilitates this gas sale. Ms. Podein states that if entering into the underlying gas transport agreement was not a prudent action by Public Service, then using this transport agreement to facilitate gas sales to Southwest Gen cannot be considered to create savings for our retail customers. The purpose of my rebuttal testimony is to provide information that will make it clear that the contract extension to this transport agreement to which Public Service agreed when settling CIG's rates were prudent even without the Gas Sales Agreement to Southwest Generation. The revenues from the gas sales to Southwest Generation therefore provide real cost savings for Public Service's electric customers.

My testimony will also rebut answer testimony presented by Southwest Generation witness Mr. Rhodes. I explain that the location of a power plant and the physical pipeline assets in the area of the power plant do make a difference in the way Public Service must evaluate pipeline capacity costs in the bid evaluation process.

III. CIG CONTRACT RENEWAL

Q. MS PODEIN TESTIFIES THAT STAFF HAS NOT YET REVIEWED THE TRANSPORT AGREEMENT THAT PUBLIC SERVICE HAS WITH CIG. WHY DO YOU BELIEVE THAT MS. PODEIN MIGHT QUESTION THE PRUDENCE OF PUBLIC SERVICE AGREEING TO EXTEND THE TRANSPORT AGREEMENT WITH CIG WHICH FACILITATES THE GAS SALE TO SOUTHWEST GENERATION UNDER THE GAS SALES AGREEMENT?

A. As part of a presettlement agreement in CIG's most recent FERC required rate case in 2011, Public Service agreed to extend all of our transport agreements with CIG through March 31, 2016. Public Service was using one of those agreements to deliver gas to Southwest Generation's Fountain Valley generation plant. The electricity output from that plant was being sold to Public Service under a "tolling" power purchase agreement through September 1, 2012. A tolling power purchase agreement is an agreement where Public Service supplies the natural gas to the IPP generator and the generator "converts" that gas into electricity. All of Public Service's recent power purchase agreements with IPPs are tolling agreements.

I assume that Ms. Podein is questioning why Public Service would agree to extend the transport agreement used to supply gas to Fountain Valley after Public Service no longer was purchasing the output from the Fountain Valley plant. As I explained in my Rebuttal Testimony, Public Service agreed to extend this agreement in order to preserve substantial rate discounts that we have under other CIG transport agreements.

Q. BEFORE DISCUSSING THE CIG RATE SETTLEMENT, IS THE CONTRACT THAT MS. PODEIN IS QUESTIONING ONLY USEFUL FOR SUPPLYING GAS TO FOUNTAIN VALLEY?

A. No. We can use that transport agreement to move gas from Western Wyoming and Colorado all the way to the Midway delivery point that is used to serve Fountain Valley. Public Service owns or has under contract numerous power plants along that route that can be served by this transport agreement.

Q. PLEASE PROVIDE INFORMATION ON THE RATE SETTLEMENT THAT INCLUDED THE EXTENSION OF THIS TRANSPORT AGREEMENT.

A. The gas transport agreement that Ms. Podein references in her testimony was entered into by Public Service as part of a comprehensive settlement agreement in CIG's latest FERC rate proceeding where the settlement was reached prior to the date on which CIG was required, under a prior settlement, to file a general rate case. I will explain why it was in our customers' interest that Public Service agree to renew this transport agreement. I will lay out what market conditions were causing CIG revenue concerns at the time of the settlement negotiations and the strategy we used to minimize the cost impact and maximize the services we received from our portfolio of CIG gas transportation contracts. I will also clarify the structure of that settlement.

Q. WHAT WERE THE MARKET CONDITIONS AT THE TIME OF THE CIG SETTLEMENT NEGOTIATIONS AND HOW DID THEY IMPACT CIG'S RATE ISSUES AT THAT TIME?

A. In late 2010 and early 2011, the gas market was starting to understand the impacts of the shale gas drilling boom and its impact on the price of natural gas and the variability of the market value of natural gas. The boom in shale gas drilling was significantly slowing the pace of drilling in the conventional gas basins as producers were moving their drilling money to the more lucrative shale plays and away from the conventional basins in Wyoming and Colorado. Many of the new shale gas plays were located in areas where gas had been in decline or where production had historically been in short supply and gas was traditionally delivered by pipeline. This change in the fundamentals of the supply and the delivery of gas was having impacts on pipelines in a number of ways, particularly if a pipeline had a number of large contracts close to expiring.

In the industry the value of the gas at different markets that a pipeline can receive gas from or deliver gas to across the nation is called "the basis." The events I describe above were having an affect on the basis across a number of pipelines. That is to say, across these pipelines the basis was decreasing to a point where the cost of firm gas transport capacity was too high to support gas marketers holding firm gas transportation capacity as they had in the past. Places like the Texas Panhandle were starting to see production growth instead of the deep decline they had seen previous to the boom in shale gas drilling. The east coast area, where gas had been in short supply causing a high price market, was starting to see production that was changing the market and causing the gas cost variability or basis that had been seen across the US to flatten. Compared to what we had seen in the past, these events were making pipeline capacity less relevant to the arbitrage of prices between production basins and markets.

Q DID THESE CHANGING MARKET CONDITIONS FACTOR INTO THE PRIMARY ISSUES THAT WERE BEING ADDRESSED BY CIG IN THE RATE CASE THEY WERE PREPARING TO FILE IN 2011?

A. Yes. When CIG presented the information on the issues that would be a part of its rate case, we could see that the primary concern faced by CIG was the loss of contracts with a number of gas marketers and producers that were firm shippers on the CIG system. In late 2010, the marketers were seeing that the 2012 foreword price variability or basis differential across the CIG system for natural gas was approximately $0.08 Dth, which cannot support a marketer with firm gas transport capacity across the system that costs about $.32 Dth in demand charges every day. This was not a sustainable business model for the gas marketers on the CIG system and we could see that they were unlikely to recontract with CIG. The producers were reducing their drilling plans and would not need as much gas transport capacity. They were also looking at alternatives to firm contracts on CIG to ship their gas production in Colorado and Wyoming. Finally, they were considering using interruptible gas transportation or an alternative pipeline if they could keep their production moving to the market and reduce their cost in the tightening gas market. Exhibit No. CD-2 is a graph made from the contract data CIG had shared with their customers during the rate settlement negotiations. The graph shows the contracts in effect for that year classified by type of customer segment. It can be seen from the graph that a significant portion of the marketer segment and some portion of the producer segment were not expected to renew or extend their contracts as they expired. The line on the graph reflects our best estimate of the CIG mainline gas transport reservation revenue we expected to be renewed because it was associated with customers that needed the CIG services to either serve their utility and electric loads or move their production to market without a settlement.

In the graph set forth in Exhibit No. CD-3 the blue bars represent the same data as shown in Exhibit. No. CD-2, the red bars reflect what we expected the CIG mainline revenue to be with the contract extensions from the settlement. The year 2016 appears small because most of the contract extensions from the settlement expire March 31, 2016, so there is only one fourth of a year's revenue.

Q. WITH THE MARKETERS AND SOME PRODUCERS LOOKING TO NOT RENEW OR EXTEND THEIR CONTRACTS WITH CIG, WHAT IMPACTS WOULD THE CHANGE HAVE TO UTILITY AND ELECTRIC GENERATION SHIPPERS?

A. We could see that the utilities, such as the Company, that used CIG to serve utility and electric generation load in the Colorado Front Range area were at risk of having their rates rise to cover the CIG pipeline costs. This information also made it clear that contract discounts would not be available to us at our next contract renewal. CIG was looking at all its options to offset the revenue losses from this expected decontracting; it was clear that CIG would have to recover its cost of service over a smaller number of billing determinants.

Q. AT THE TIME OF THE CIG SETTLEMENT NEGOTIATIONS, WHAT WAS THE STATUS OF PUBLIC SERVICE'S TRANSPORT CONTRACTS WITH CIG?

A. Public Service has 11 firm mainline CIG gas transport and storage contracts. We use these contracts to move gas from Wyoming, Western Colorado, the Cheyenne market hub and Gas Storage to our gas distribution system. We use these contracts to move gas to Public Service-owned power plants and power plants owned by Independent Power Producers that sell electricity to Public Service under "tolling" power purchase agreements. Under five of these mainline CIG transport contracts (two for the Gas LDC and three for electric generation), Public Service had negotiated a significant discount from CIG's tariff rates. We had been able to obtain these discounts because in the past we had developed bypass and expansion options and CIG had matched the price we had obtained on these options. CIG indicated that without a rate settlement it would push to price the five mainline CIG discounted gas transportation contracts up to the CIG full rate when they expire. Exhibit No. CD-4 is a graph that compares the five mainline CIG electric gas

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transportation contracts (two full rate and three discounted) with the continuation of discounts negotiated as part of the rate settlement to the contracts priced at the CIG full rate.

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Q. WHAT WAS THE STRATEGY PUBLIC SERVICE EMPLOYED TO MINIMIZE ADVERSE IMPACTS ON THE PUBLIC SERVICE HELD CIG GAS TRANSPORTATION CONTRACTS FROM THE PROBLEMS FACED BY CIG?

A. Public Service could see that the utility and electric generation shippers that had no quickly accessible alternative gas transportation options would be the CIG customers that would see their rates rise when their contracts were renewed. We were concerned that we would lose some or all of the discounts that we had under our then current contracts. To minimize this rate impact, we worked to do four things: 1. Get the pipeline to take responsibility for a significant portion of the decontracting; 2. Keep the customer groups like Gas LDC's, Electric Generators and Producers covering the costs of service they had historically been covering if they did not have an alternative way to transport their gas; 3. Find a way to keep our rate discounts when it was time to extend our contracts; 4. Maximize the amount of services we were getting from CIG for the cost of service we were covering.

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Q WHY WAS IT IMPORTANT TO HAVE THE CUSTOMERS FOR WHOM THE SYSTEM WAS BUILT CONTINUE TO COVER THE COST OF SERVICE THEY HAD BEEN COVERING.

A When there is decontracting on the CIG system, it is important to have the customers for whom the system was built continue to support the system cost of service that they had. If we do not keep the current customers paying for the system cost of service during a period of decontracting, then the captive customers will be trapped and forced to pay for all of the costs not covered by the decontracting customers. During the periods of expansion in the gas business, it is not an issue if a customer does not renew or extend capacity since the pipeline can usually resell the capacity. When the market is in decline, the ability to resell the capacity is not as likely so the costs then need to be shifted to other customers or absorbed by the pipeline.

Q IS IT NORMAL FOR THE PIPELINE TO ABSORB THESE DECONTRACTING REVENUE LOSSES AND NOT PASS THEM BACK TO THEIR CUSTOMERS?

A During the settlement discussions it was made clear by CIG that it would absorb the costs between rate cases but in subsequent rate cases CIG would do all it could do to recover as much cost as possible by either eliminating contract discounts where possible and shifting the costs to the remaining customers. CIG even threatened that if decontracting continued without a settlement they would file back to back rate cases to recover the lost revenues.

Q GIVEN THESE ISSUES, WHAT TYPE OF A SETTLEMENT WAS REACHED?

A. The settlement, which has been approved by FERC, 136 FERC ¶ 61,103 (2011), accomplished most of Public Service's strategy for minimizing increases in our costs of shipping on CIG. Under the settlement, there was no general increase in the pre-existing rates. In addition, we were able to develop a revenue credit / surcharge mechanism that required CIG to share 80% of any mainline revenues above $260 million; it also allowed CIG to collect 80% of the revenue shortfall below the $250 million. This credit or shortfall will be calculated annually after CIG has the year's revenue numbers in place. This mechanism was developed to have CIG absorb the first $10 million of revenue shortfall and then the customers would share an 80% portion of the revenue shortfalls. The settlement required utility and electric customers to extend their contracts through the proposed term of the settlement, *i.e.* through March 31, 2016. That provided CIG some assurance that if it agreed to the sharing portion of the settlement regarding decontracting risk that it reduced its decontracting exposure by getting as many customers as possible to extend their current contracts through the term of the settlement.

The gas utility and electric generation customers, as well as some of the producers agreed with the recontracting. The recontracting at current rates would not cost us more than we had been paying for the gas transportation services and it was a good way to keep customers paying for their share of their historic cost of service. We also could see that the customers who did not have options to CIG for delivering gas to their loads were going to pay at least a portion of the revenue shortages.

Q. DID THE SETTLEMENT RECONTRACTING REQUIREMENT CAUSE PUBLIC SERVICE TO EXTEND MORE CONTRACT GAS TRANSPORT CAPACITY THAN WAS NEEDED OVER THE COURSE OF THE CONTRACT EXTENSIONS?

A. The gas transport capacity that was recontracted was and is being used by Public Service electric generation as a part of the pool of contracts necessary to deliver gas to Public Service owned generation and to IPPs who have tolling power purchase agreements with Public Service. The process of settling the CIG rate case was necessary and important to ensure that we could extend these contracts at the significant discounts we currently have. Achieving a utility rate settlement always involves a series of negotiations and compromises to get the best result possible at that time. The compromise of extending all of the contracts was necessary to achieve settlement, preserve the discounts, and minimize our exposure to the decontracting. In my view, CIG would not have settled the case without the contract extensions.

Q. IN 2016 WHEN THE CIG CONTRACTS WILL AGAIN EXPIRE, WILL PUBLIC SERVICE NEED TO SETTLE A RATE CASE TO ENSURE THAT WE ARE IN A POSITION TO GET CONTINUED DISCOUNTS?

A. The CIG settlement was negotiated in early 2011. Since then, there has been a major change in the gas supply situation in the Colorado Front Range area. The development of the oil and natural gas in the Niobrara shale has taken off with several producers making major drilling program announcements and three new large natural gas processing plants being developed with two of them under construction. Public Service is also working on the development of the new pipeline from Fort Lupton to the Cherokee Clean Air Cleans Jobs power generation redevelopment. This pipeline will start out near an area where we are developing a hub that will be able to deliver gas to Public Service's two current (Rocky Mountain and Ft St

Vrain) and one new (Cherokee) combined cycle power plants. This point will also be able to swing gas between the plants if needed as well as access the Totem storage service through the CIG TSB-T pipeline services. The hub point will also have access to the CIG and CIG High Plains pipeline, as well as the Public Service LDC system that connects to the Cheyenne hub through the Public Service Front Range pipeline. These changes will improve the situation for gas transportation and access to gas supply into the core gas delivery area for electric generation. As such, Public Service should be in an excellent position to negotiate continued discounts with the pipelines.

IV. POWER PLANT LOCATIONS AND ASSIGNED TRANSPORTATION COSTS

Q. MR. RHODES IN HIS TESTIMONY INDICATES THAT THE FOUNTAIN VALLEY POWER PLANT LOCATION SHOULD NOT HAVE A DIFFERENT RATE FOR GAS TRANSPORTATION IN THE BID EVALUATION THAN A POWER PLANT IN THE PUBLIC SERVICE CORE DELIVERY AREA. DO YOU AGREE?

A. No I do not agree. The location of the Fountain Valley plant does have an impact on the cost of delivering gas to the location. It is significantly farther from the Cheyenne Hub, which is the primary market hub for gas supply in the Colorado Front Range, than our generation plants located in what we described as our core delivery area; and the Fountain Valley plant does not sit in or near the significant drilling and increasing gas production area of the Denver Julesburg (DJ) basin. The core gas delivery area location is close to the Cheyenne Hub and it sits on the growing production of the DJ basin, making access to supply at deeply discounted gas transportation rates possible. Public Service Electric currently has a number of discounted CIG gas transportation rates in the core delivery areas and the capacity weighted average demand rate for gas transportation in the core delivery area is $3.51 per Dth – month. CIG has always pushed to get the full tariff rate for gas transportation with a delivery point south of the Denver area, where Fountain Valley is located. Public Service has two gas transportation contracts for the electric generation with delivery points south of Denver and one is at the CIG TF-1 maximum tariff rate of $9.65 per Dth – month and the other has a slightly discounted rate of $8.18 per Dth – month. As you can see there is a significant difference in the cost of the gas transportation required to serve the Fountain Valley facility as compared to plants located in the core delivery area and this differential needs to be accounted for in the bid evaluation process.

Q. DO YOU AGREE WITH MR. RHODES' RECOMMENDATION THAT GAS TRANSPORTATION COSTS FOR BIDS BE BASED UPON THE ACCESS THAT EXISTING PLANTS CURRENTLY HAVE?

A. No. The majority of the contracts on the CIG system currently held for the electric generation portfolio expire on March 31, 2016. Public Service will be using this opportunity to re-evaluate our firm requirements and contract for a portfolio accordingly. Therefore, using a methodology as I described in my direct testimony assigns costs based on the incremental costs to provide natural gas supplies to plants offered into the bid process.

Q. IN REVIEWING THE TRANSPORTATION MATRIX FROM YOUR DIRECT TESTIMONY IN PREPARING THIS REBUTTAL TESTIMONY, DID YOU DISCOVER THAT YOU WERE REQUIRED TO MAKE ANY CHANGES?

A. Yes. The Transport Cost for RFP Evaluation in the last section should be changed to reflect the use of the *delta* in demand charges that the Company expects to experience in the CIG core gas delivery area and the demand charges that the Company expects to incur in providing firm transport (if deemed necessary) to plants that fall into the last section's definition. Table CD-1 below has been revised with language to effectuate the change described above.

<u>Table CD-1</u>

Generation Location	Pipeline Connection	Transport Cost for RFP Evaluation
CIG core gas delivery area	Connected to the CIG High Plains pipeline or other CIG pipeline in the core gas delivery core area	CIG Firm commodity charges and FL&U and PSCo balancing charges. The balancing charges will not be used if the generation is connected to the CIG High Plains pipeline system
Denver Metro area or in Northern Colorado	Connected to PSCo Gas LDC or other Gas LDC	CIG Firm commodity charges and FL&U, *plus* the full rate gas distribution IT commodity rate and FL&U, as well as the PSCO balancing charges.
Other Areas	Connected to CIG pipeline not in the core gas core delivery area.	If the CIG can provide IT transportation April through October and on Cold but not extremely cold days in the winter, then the charges will be full rate CIG IT commodity and FL&U

Generation Location	Pipeline Connection	Transport Cost for RFP Evaluation
Denver Metro area or in Northern Colorado and Other Areas	Connected to the CIG pipeline not in the core gas delivery area where the IT services are limited in availability. Or to the PSCo or other gas LDC in an area with limited IT service.	If the CIG pipeline or the gas LDC cannot provide IT transportation April through October and on Cold but not extremely cold days in the winter, then we will work with CIG and / or the Gas LDC to determine what needs to be done to firm up the gas transport. This may require that the delta between the firm demand rate to provide service to a plant that meets these criteria versus the demand rate associated with providing firm deliveries to a plant in the core area be added to the cost of the gas transport.

Q. MR. RHODES INDICATES IN HIS TESTIMONY THAT IT IS UNREASONABLE TO USE FULL RATE INTERRUPTIBLE TRANSPORTATION AS A COMMODITY RATE COMPARED TO USING THE FULL RATE FIRM COMMODITY RATE OR TO ASSIGN A FIRM RESERVATION CHARGE TO FOUNTAIN VALLEY. CAN YOU EXPLAIN WHY THE PROPOSED METHODOLOGY IS REASONABLE?

A. As described above, location matters in the cost of providing natural gas to the plant. Plants located in the Core Area have multiple transportation options, which allows the Company to negotiate advantageous pricing terms for firm transportation services, whereas plants located outside of the Core Area have limited options and therefore typically demand full rate transportation costs. Therefore it is reasonable to use the matrix shown above to assign the costs based on the anticipated level of service (IT or Firm) needed to provide natural gas to the Fountain Valley facility or any other facility outside of the Core Area in order to evaluate all plants on an equivalent basis in the bid evaluation.

Q. MR. RHODES INDICATES THAT THE TEST THAT WAS PROPOSED FOR DETERMINING WHETHER RELIABLE INTERRUPTIBLE CAPACITY IS AVAILABLE IS NOT NECESSARY. DO YOU AGREE?

A. I do not agree. The test is necessary to be sure the power plants that are being evaluated can be available to operate on interruptible gas transportation when the plant is needed during the critical summer peak power conditions and during the maintenance outages for other plants during the spring and fall maintenances periods. If interruptible gas transportation is not reliably available for power plants that are bid to operate during the peak need times, it would be difficult to justify paying the capacity charges for the purchase power capacity of these plants. If interruptible gas transportation is not reliable we need to evaluate the purchase power bid with firm gas transportation costs to ensure that we can justify paying capacity charges to the IPP and to be sure the plant could be used for generation when needed by the system.

Q. MR. RHODES SUGGESTS THAT THE PROCESS FOR DETERMINING WHETHER RELIABLE INTERRUPTIBLE CAPACITY IS AVAILABLE WILL BE DETERMINED BY PUBLIC SERVICE ELECTRIC AND THAT THE PROCESS LACKS PREDICTABILITY. DOES PUBLIC SERVICE ELECTRIC MAKE THIS DECISION AND HOW ARE THE RESULTS APPLIED?

A. No. Although Public Service Electric expects to work with the upstream pipelines to determine capacity availability on each pipeline's system at locations proposed by the bidders, the upstream pipelines (including Public Service LDC) make the determination for what level of service would be available at each proposed location. Public Service Electric will rely on the information provided by the upstream pipelines to then appropriately assess charges to the bids in accord with the process laid out in my rebuttal testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does