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July 26, 2021

Ms. Shonta Dunston
Acting Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4300

RE: **Application of Public Service Company of North Carolina, Inc. for Annual Review of Gas Costs Pursuant to N.C. Gen. Stat. § 62-133.4 and Commission Rule R1-17(k)(6), Docket No. G-5, Sub 635**

Dear Ms. Dunston:

Enclosed for filing is the Direct Testimony and Exhibits of Gregory M. Lander on behalf of the Haw River Assembly.

Pursuant to Commission Rule R1-28(e)(1), we plan to deliver via overnight mail fifteen (15) three-hole punched paper copies, one of which shall be single-sided, of the entire filing to the Commission on or before July 27, 2021.

If you have any questions, please let me know.

Sincerely,

David L. Neal

Enclosures
cc: Parties of Record

**BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

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| **In the Matter of: Application of Public Service Company of North Carolina, Inc. for Annual Review of Gas Costs Pursuant to N.C. Gen. Stat. § 62-133.4 and Commission Rule R1-17(k)(6)** | ) | **DOCKET NO. G-5, SUB 635** |

**DIRECT TESTIMONY AND EXHIBITS OF**

**GREGORY M. LANDER**

**ON BEHALF OF**

**HAW RIVER ASSEMBLY**

**July 26, 2021**

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## I. <u>Introduction and Qualifications</u>

**Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND EMPLOYMENT.**

A. My name is Gregory M. Lander. My business address is 83 Pine Street, Suite 101, Peabody, MA 01960. I am President of Skipping Stone, LLC ("Skipping Stone"). With Skipping Stone, I head-up our Energy Logistics and Energy Contracting practice line.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. The Haw River Assembly ("HRA").

**Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?**

A. I graduated from Hampshire College in Amherst, Massachusetts, in 1977, with a Bachelor of Arts degree. In 1981, I began my career in the energy business at Citizens Energy Corporation in Boston, Massachusetts ("Citizens Energy"). I became involved in the natural gas business of Citizens Energy in 1983. Between 1983 and 1989, I served as Manager, Vice President, President and Chairman of Citizens Gas Supply Corporation (a subsidiary of Citizens Energy). I started and ran an energy consulting firm, Landmark Associates, from 1989 to 1993, during which time I consulted on numerous pipeline open access matters, a number of Federal Energy Regulatory Commission ("FERC") Order No. 636 rate cases, pipeline certificate cases, fuel supply and gas transportation issues for independent power generation projects, international arbitration cases involving renegotiation of pipeline gas supply contracts, and natural gas market information requirements cases (FERC Order Nos. 587 et seq.). In 1993, I founded TransCapacity LP, a software and natural gas information services company. Since 1994, I have also been a Services Segment board member of the Gas Industry Standards Board ("GISB") and its successor organization, the North American Energy Standards Board ("NAESB"). During the period 1994 to 2002, I served as a Chairman of the Business Practices Subcommittee, the Interpretations Committee, the Triage Committee, and several GISB/NAESB Task Forces.

I am currently a Board Member of NAESB and have served continuously in that capacity since 1997. Skipping Stone, Inc. acquired TransCapacity in 1999, and since that time I have headed up Skipping Stone's Energy Logistics and Energy Contracting practices, where my specialization has been interstate pipeline capacity issues, information, research, pricing, acquisition due diligence and planning.

From 1984 to present, I have maintained a deep familiarity with a wide range of pipeline transportation and contracting issues, beginning with access to pipeline capacity to make competitive sales, resolution of the pipeline take-or-pay contracting regime, pipeline affiliate marketer concerns, restructuring of the pipelines from merchants to transporters and thereafter, and definitions of what constituted a pipeline capacity "right" for the purposes of formulating the then newly commenced capacity release and capacity rights trading business process. I continue to be involved in nearly all facets of the capacity information and trading business as part of my duties at Skipping Stone. In addition, I have been the lead principal on all 50 plus pipeline and storage mergers and acquisitions transactions as well as all pipeline and storage facility expansion projects for which Skipping Stone has been retained by potential purchasers and project sponsors to provide economic due diligence consulting and market analysis.

**Q. HAVE YOU FILED TESTIMONY IN REGULATORY PROCEEDINGS PREVIOUSLY?**

A. I have filed testimony in several regulatory proceedings. Since 2004, I have filed testimony and/or reports in several proceedings before FERC and state public utilities commissions, including in Maine, Massachusetts, New York, New Jersey, Missouri, California, the District of Columbia, Virginia and South Carolina. Please refer to Exhibit GML-1 for my current CV and Exhibit GML-2 for a full list of case names in which I have filed direct and surrebutttal testimony.

## II. Testimony Overview

**Q. WHAT DO YOU ADDRESS IN YOUR TESTIMONY?**

A. The purpose of my testimony is to present my All-In Cost Analysis of Public Service Company of North Carolina, Inc.'s (PSNC or the Company) acquisition of firm pipeline capacity on the Mountain Valley Pipeline (MVP) and the MVP Southgate pipeline. I reviewed the Company's application materials, its responses to data requests, and publicly available information about the MVP and MVP Southgate projects. Using this information, I performed an All-In Cost Analysis of PSNC's MVP and MVP Southgate capacity and reached the following conclusions.

First, PSNC projects increasing winter-peak demand from its customers. Because its projected increase in demand is both modest and of short duration, only occurring for a few hours on the coldest winter days, PSNC's purchase of year-round firm capacity on the MVP and MVP Southgate projects is an extremely expensive solution. The total fixed cost of this capacity is over $120 million per year, equal to an estimated 2022-23 All-In Cost of $324.22 (fixed cost) for each Dth of gas estimated to be actually used by PSNC's customers through the incremental capacity represented by the MVP/MVP Southgate contracts.

Second, PSNC has other alternatives available to meet its projected demand, including contracting directly with gas producers and marketers that own capacity on the existing Transco pipeline and able to deliver to PSNC. PSNC already contracts with some of these types of companies to meet its winter-peak demand, and my analysis shows that this merchant capacity will be sufficient to meet PSNC's demand projections until at least 2035. The All-In Cost of gas delivered by merchants on the existing Transco system is likely substantially lower than the All-In Cost (including gas cost) of PSNC's MVP and MVP Southgate capacity. PSNC's application provides no indication that the Company has evaluated this—or any other alternative option—to identify the lowest-cost resource for its customers.

Third, PSNC's decision to contract for MVP/MVP Southgate capacity will not only affect its firm gas customers, but also large commercial and industrial gas users that transport gas on the PSNC system and electric ratepayers in North Carolina whose rates reflect changes in PSNC's fixed demand costs.

In light of these conclusions, I recommend that the Commission put PSNC on notice in its final order in this case that the contracted capacity on the MVP and MVP Southgate pipelines is far in excess of PSNC's demonstrated need. Alerting the Company now that it is at risk for not recovering the costs of its excess pipeline subscription will allow PSNC to take advantage of viable market alternatives for disposing of its MVP and MVP Southgate capacity to reduce these significant and unjustified costs.

**Q: WHAT MATERIALS HAVE YOU REVIEWED FOR THE PURPOSE OF THIS TESTIMONY?**

A: I reviewed the following: Public Service North Carolina's (PSNC)'s contract data; Transcontinental Gas Pipe Line (Transco) filed contract data known as its Index of Customers; Transco posted capacity release data for releases of capacity which releases were effective during the review period of this case. I also reviewed PSNC's witnesses Jackson's and Creel's respective testimony and Exhibits; the November 15, 2018 North Carolina Department of Environmental Quality letter to the Federal Energy Regulatory Commission (FERC) with regards to the proposed Southgate extension of the Mountain Valley Pipeline; PSNC's August 16, 2018 application to the North Carolina Utilities Commission with respect to its Mountain Valley Pipeline (MVP) and Southgate (MVP Southgate) precedent agreements (PSNC Application); the Commission's October 9, 2018 Order with respect to PSNC's MVP and MVP Southgate precedent agreements; NCUC Rule R1-17(k) - Procedure for Rate Adjustments

Under GS 62-133.4 In addition, I also reviewed PSNC Responses to Data Requests submitted for HRA by Southern Environmental Law Center (SELC).[1]

## III. <u>PSNC'S Approach to Gas Procurement</u>

**Q: WITH RESPECT TO YOUR REVIEW OF PSNC WITNESS JACKSON'S TESTIMONY, DO YOU HAVE ANY INITIAL OBSERVATIONS?**

A: As stated by Jackson, with respect to its priorities as regards gas procurement, PSNC puts supply security first, above cost; next is operational flexibility; and then third is cost. They call this 3-part gas procurement approach a "best-cost" supply strategy. Jackson Direct at 4:5-7.

**Q: IS THIS "BEST-COST" STRATEGY A COMMON ONE AMONG LOCAL DISTRIBUTION COMPANIES (LDCS) THAT YOU ARE FAMILIAR WITH?**

A: This is the first articulation of this sort of strategy that I have encountered. Usually, LDCs articulate a "least-cost" procurement process as their primary strategic priority followed by supply security.

**Q: DOES PSNC'S "BEST-COST" ARTICULATION RAISE ANY ISSUES IN YOUR OPINION?**

A: On the face of it, the primary problem with this approach is that there is no monetarily quantifiable measure for either of the first two of these "best-cost" metrics. They are entirely subjective. Another way to characterize "best-cost" is "best price." To identify "best price," we would need to first look at the likely result, in terms of what *<u>is</u>* the cost, in dollars per dekatherm (Dth) of meeting peak-day demand; and what *<u>is</u>* the cost in dollars per Dth of incremental gas that

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[1] Because PSNC's responses to data requests were provided in one document that contained both confidential and non-confidential information, I have included as exhibits to my testimony only those individual requests and PSNC's responses to those individual requests that I reference, none of which were designated as confidential. The Company's responses are otherwise unchanged.

will be used (i.e., burned) as a result following such approach, especially relative to possible alternatives.

**Q: DOES PSNC'S "BEST-COST" ADEQUATELY CONSIDER LESSER-COST OPTIONS THAT COULD ALSO MEET THE COMPANY'S NEEDS?**

A: No. In short, the question is, or should be: at what price is PSNC asking ratepayers to agree with PSNC that PSNC is in fact pursuing a "best price/best-cost" approach? This question is especially relevant here with respect to a multi-decade cost stream that is potentially facing PSNC ratepayers, namely the costs of its MVP/MVP Southgate subscription decision. Essentially, PSNC is asking ratepayers to bear and accept the costs for MVP Southgate capacity as the "best-cost" option, but PSNC has provided no evidence that it compared the costs of this new pipeline capacity with other options.

In order to answer such a question, or take PSNC's characterization as accurate or dispositive, we should have seen in the PSNC Application a presentation of MVP/MVP Southgate versus a presentation of ***alternatives*** and at what other price(s) could there be for meeting the same peak demand and Dth of incremental usage as between such ***alternatives.***

While I recognize that no costs resulting from PSNC's contracts for MVP/MVP Southgate capacity have yet been incurred or passed along to PSNC's ratepayers, there may be few remaining opportunities for the Commission to consider the risks to ratepayers before such costs are incurred and proposed to be recovered. For this reason, my recommendations are focused on action(s) the

Commission could take in this docket to put PSNC on notice of being at risk for not recovering imprudently incurred costs.

**Q: DID PSNC EVALUATE A RANGE OF ALTERNATIVES FOR MEETING ITS PROJECTED INCREASED DEMAND?**

A: I do not know. However, based upon the plain language in the PSNC Application, PSNC did not state that it circulated RFPs for a wide range of solutions to meet proposed peak demand over time. Instead, they essentially asked "who has a pipeline proposal for me?" In particular, PSNC did not state that it asked for energy efficiency (EE) proposals that would reduce peak demand by 2%, 4%, or by any amount, and the Company did not identify what such alternatives would cost. PSNC also did not articulate that it looked for non-pipeline alternatives (NPAs), like increasing liquefied natural gas (LNG) vaporization at its existing Cary LNG facility, adding a satellite LNG or satellite compressed natural gas (CNG) station(s), or identify what these approaches would cost.

In its own words, PSNC did not ask any of these questions, nor, according to the PSNC Application, did it get any RFPs to evaluate potential other solutions to evaluate against a massive pipeline solution. It appears from the PSNC Application that the Company took the view that there was only one way to solve what it perceived as the "problem." It is not clear whether PSNC bounded the problem it sought to solve. This is evident because a simple calculation of how long it would take for PSNC's load to grow into the MVP/MVP Southgate pipeline expansion, based upon its own forecasted growth rate, shows that it will take 12 or more years of the 20 years that PSNC has contracted for, to make use of the capacity to meet design day demand. In my opinion, PSNC has vastly over-purchased new pipeline capacity in light of its projected growth.

## IV. Introduction to All-In Cost Analysis

**Q: HOW, IN YOUR OPINION, WOULD SUCH A COMPARATIVE EVALUATION BE CONDUCTED?**

A: The Company should use "All-In Cost Analysis" in evaluating capacity resource renewal, expansion of its capacity resources, and viable alternatives, including non-pipeline alternatives. Jackson Direct at 9:1-5.

**Q: IS ALL-IN COST ANALYSIS USED IN THE GAS INDUSTRY?**

A: Yes. As an example, in recently filed testimony before the New York Public Service Commission, I testified that National Grid should adopt All-In Cost Analysis. Like PSNC, National Grid is a local gas distribution company. The settlement filed in that case adopted that All-In Cost Analysis be used in evaluation of proposed capacity resource expansion measures proposed by National Grid to meet projected peak period demand increases.

**Q: WHAT IS ALL-IN COST AND HOW IS IT USED?**

A: All-In Cost is a method of analysis that enables the apples-to-apples comparison of respective costs of alternative means for achieving a defined goal.

**Q: PLEASE EXPLAIN.**

A: The first step in the All-in Cost analysis process is to define the problem (i.e., the "*<u>what</u>*" to be addressed) and to define as the goal, addressing and eliminating the problem (i.e., the "*<u>how</u>*"). PSNC does that in this case: The Company projects that it and its customers face a potential shortfall in PSNC resources to meet Design Day Requirements, or, said another way, PSNC has stated that meeting

Design Day Requirements is the "*what"* that PSNC will have to be prepared to meet. That "*what*" is its firm customers' maximum single day demand (i.e., Design Day Demand).

**Q: DOES PSNC ACCURATELY IDENTIFY THE PROBLEM IT FACES?**

A: Not entirely. I note that having a single measure of the "problem" to be solved misses at least one corollary aspect. That corollary aspect is an equally important component of the "problem" to be solved; namely the forecasted *duration* of requirements exceeding projected or known PSNC resources.

**Q: WHY IS FORECASTED DURATION IMPORTANT?**

A: Forecasted duration is important because there are different, economically superior, or inferior, means of achieving the "goal", (i.e., solving the "problem") depending on how long each year PSNC's projected resource shortfall exists. In other words, to accurately assess PSNC's options, we need to know the following: what is the period of time—either consecutive or intermittent—that projected demand exceeds PSNC resources and in what magnitude are resources exceeded across the pertinent period.

**Q: BEFORE YOU CONTINUE, DO YOU HAVE ANY KNOWLEDGE THAT DURATION OF INCREASED DEMAND WAS *NOT* AN IMPORTANT CONSIDERATION OF PSNC?**

A: Yes. When asked in a data request about what market PSNC has for the balance of the capacity beyond that to serve peak day growth, PSNC responded: "The question incorrectly assumes that PSNC acquires capacity to meet the annual needs of its customers. Rather, the capacity is maintained ***at a level to meet PSNC's firm demand on the coldest day*** to ensure reliable service to firm sales customers."[2] [emphasis added] This means that duration of demand was not a primary consideration, if it was considered at all.

**Q: PLEASE EXPLAIN HOW DURATION WOULD INFLUENCE PSNC'S DEFINITION OF ITS PROBLEM.**

A: Let me give three examples. First, if projected maximum demand is forecasted to exceed PSNC resources during a single day and, for all other days, demand can be met by existing resources, that is one problem to be solved. Second, if projected maximum demand is forecasted to exceed PSNC resources for an entire year, then that is another, and different, problem to be solved. And, third, if projected maximum demand is forecasted to exceed PSNC resources on a day, or, number of days, and on other days over a defined period, demand is expected to exceed existing resources, but to a lesser extent, that is yet a different problem to be a solved.

This set of simple examples makes it clear that correctly defining the problem correctly defines the goal for which a right-sized solution can be identified to meet.

**Q: HOW DOES THIS RELATE TO AN ALL-IN COST ANALYSIS OF PSNC'S PROJECTED RESOURCE SHORTFALL?**

A: There are, as we see from the three examples, two components to PSNC's shortfall. First, there is the maximum demand that a proposed solution must address and, with it, its corollary cost per unit of demand met. Second, there is the total incremental demand (i.e., units of individual demand that must be met) over the duration where demand exceeds resources to any extent. When

[2] PSCNC's Response to Haw River Assembly's Data Request, Item 1-29 in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-3)

performing All-in Cost Analysis, there is a cost per unit to each of these two components. And, to enable comparison between different means of meeting these two components of the problem, All-in Cost Analysis presents each of these two components in per unit amounts enabling apples-to-apples comparisons between the different alternatives capable of solving the same defined problem.

**Q: CAN YOU PROVIDE AN EXAMPLE OF HOW THE ALL-IN COST ANALYSIS WORKS?**

A: The first component of an All-in Cost Analysis involves presenting the cost in per Dth per day or the cost per Dth per hour of meeting the maximum demand. A simple example is as follows: assume that the maximum shortfall of existing resources is projected to be 1,500 Dth per hour on the Design Day.

**Q: BEFORE YOU CONTINUE, WHY DID YOU USE DTH PER HOUR AS YOUR MEASURE?**

A: Because local gas distribution companies (LDCs) typically experience their peak daily demand in one or more hours between 6:00 and 8:00 AM in the winter, and, for that demand, LDCs have to make the gas be there when it is needed. It is not all right for gas needed at 7:00 AM to come at 12:00 Noon. If it is needed at 7:00 AM, it has to be there at 7:00 AM, period. It is rare, but possible, that the peak hourly demand persists for much of a day. In general, on very cold days, as much as 10% of daily firm customers' demand is experienced in the peak hour with the remaining 90% of firm customers' daily demand spread, in varying hourly percentages, across the other 23 hours of the day.

What this means is that the solution has to address the peak hourly demand. Of note, in the pipeline business, the vast majority of pipeline capacity contracts provide for "ratable delivery obligations." This means that the pipeline is only obligated to make delivery of 1/24th of the daily contracted quantity every hour. Often the pipeline is able to make non-ratable deliveries, and they do when they can, but they are only obligated to make "ratable deliveries." In part, this is because gas production, out of the ground, is even throughout the day. In addition, when a pipeline's system is experiencing maximum demand on a day, it does not have slack capacity to hold, or provide to its customers gas at rates other than ratable because the line is completely full and fully pressurized. The significance of this is that if an LDC needs 1,500 Dth per Hour, then, to contractually meet that hourly demand (with pipeline capacity), the LDC has to contract for 36,000 Dth per day (1,500 times 24) even though they may only need a total of 15,000 Dth for the whole day. In regard to pipeline operations, the differences between these two numbers (i.e., 36,000 and 15,000) is handled by injections into and withdrawals out of storage throughout the day. But in order to have 1,500 Dth per hour available, the pipeline has to have the equivalent of 36,000 Dthd of capacity.

As an aside, these operational facts are why LDCs often have on-system storage, and in the case of PSNC, that on-system storage is LNG that PSNC can vaporize (or not) hourly to meet demand more economically than having pipeline capacity coupled with storage service attached to the pipeline to meet that peak hourly demand and handle excess and deficient hourly supply relative to daily demand.

**Q: RETURNING TO YOUR DISCUSSION OF MAXIMUM DEMAND, HOW DOES AN "ALL-IN COST ANALYSIS" RELATE TO THE PROBLEM THAT PSNC SAYS THAT IT NEEDS TO SOLVE?**

A: Getting back to the "hourly problem" to be solved, assume that one solution, a year-round pipeline capacity solution, costs $1.50 per Dthd for a 36,000 Dthd amount of capacity to provide the 1,500 Dth per hour. That $1.50 per Dthd would cost $54,000 per day. And, were that that solution a pipeline capacity solution, it would have to be paid for every day for 365 days per year, which then means that the $54,000 per day turns into a solution costing $19,710,000 per year. Stated on a Dth per hour basis the $19,710,000 cost works out to a cost of $13,140 per Dth hour (i.e., $19,710,000 divided by 1,500 Dth per hour). In other words, the All-in Cost Analysis allows us to see very clearly something that is intuitive but often overlooked with regard to pipeline capacity: a year-round solution for a short-term maximum demand problem is often unreasonably expensive.

**Q: HOW DOES THE ANALYSIS OF THE SECOND COMPONENT, TOTAL INCREMENTAL DEMAND, WORK?**

A: For the second component of the All-in Cost Analysis, we need to look at how many incremental Dth in total are needed to meet the demand that exceeds existing resources at any given time (even though it may exceed by a de minimis amount in any hour) over the excess demand period. For simplicity, assume that there are 501 hours over the winter that firm hourly demand exceeds existing resources: these 501 hours is the *duration*. Continuing this hypothetical, assume that the maximum hourly demand is experienced once and the other 500 hours have excess demand spread proportionately over the range of 1 Dth per hour to 1,499 Dth per hour above existing resources. This total demand then would be

375,750 Dth of total *use* of the resource that provided 1,500 Dth per hour of capacity.

**Q: IN THIS EXAMPLE, HOW DO YOU ASSESS THE COST RELATED TO THE TOTAL INCREMENTAL DEMAND COMPONENT?**

A: To assess the fixed cost of the solution spread over the *usage* of the solution, we take the $19,710,000 of total cost and divide it by the 375,750 units of usage. This calculation yields a fixed cost per Dth used of $52.45 per Dth used. Now, to complete the second measure of the All-in Cost Analysis we have to assume a gas cost, (i.e., the variable cost of the gas that the solution will use). Given that we are considering the winter season, we can assume an average cost for the duration period of $3.50 per Dth. The cost per Dth used will fluctuate, but the $3.50 per Dth average will suffice for this analysis. Adding the $3.50 per Dth average gas cost brings the All-in Cost per Dth actually used to $55.95. Or, for the purposes of how LDCs charge their customers, the incremental cost of the gas *used* is $5.95 per Therm for this solution.

**Q: FOR THE PURPOSES OF MAKING A COMPARISON, IS THERE AN ALTERNATIVE SOLUTION FOR WHICH YOU COULD PROVIDE THE SAME ALL-IN COST ANALYSIS?**

A: Yes. One alternative could be a non-pipeline alternative (NPA) which used a satellite LNG station.

**Q: WHAT IS LNG?**

A: LNG is liquefied natural gas. Satellite LNG is usually a trailer truck borne solution where the LNG is in insulated tanks that are moved to and from the refill location and the satellite injection location. To establish a satellite LNG location, a header is constructed with a vaporizer to accept hookups to multiple stationary

LNG trailers (that are refilled by the LNG truck borne trailers) and a tap from the header is made into an LDC's mainline.

**Q: HOW WOULD YOU CALCULATE THE COSTS FOR AN LNG SOLUTION?**

A: A typical LNG Trailer will hold between 10,500 and 16,400 gallons of LNG. That means that each LNG trailer holds between 850 Dth and 1,340 Dth. An installation capable of delivering 1,500 Dth per hour and 15,000 Dth per day (also referred to as Dthd) would conservatively require 20 trailers of LNG. At $150,000 per trailer ($3 million or 20 times $150,000) and an equal amount for site work and related costs, a satellite LNG location would cost about $6 million. Rounding this up for engineering and overheads to even as much as $10 million of capital expense; and, then earning a 15% return and depreciating this asset over 5-10 years would yield a first-year fixed cost (before taxes) of $3.5 million per year (using 5-year useful life). This would equate to a bit less than $9,600 per day compared to $54,000 per day for the pipeline solution.

Then, for variable cost, we have to include staffing of the location during the winter period, and the cost of LNG to fill and to be used during the same period as that for the pipeline solution. Assuming 24/7 staffing by three trained personnel and accounting for time-off and related staffing costs, it would require 14 persons at about $120,000 per year or a total O&M variable of $1.7 million. Then we also have to account for the cost of the LNG. Even assuming a $10 per Dth LNG cost for each of the 375,750 Dth used plus the 17,500 Dth of initial fill gas for a total of about 400,000 Dth (inclusive of refill boil-off not used during peak period refills) you have about $4 million of gas cost. This would bring variable cost to $5.7 million ($1.7 million O&M plus $4.0 million gas cost).

**Q: WHAT IS THE END RESULT OF THE ALL-IN COST ANALYSIS FOR THE LNG ALTERNATIVE?**

A: Then, to complete the apples-to-apples comparison, we take the sum of annual fixed costs ($3.5 million) plus annual "variable" or "use" costs ($5.7 million) for a total of $9.2 million and divide that by Dth used by the solution. That then works out to $24.48 per Dth used "All-in" ($9.2 million divided by 375,750 Dth = $24.48 per Dth) or about half of the cost of the pipeline alternative (52% of the pipeline costs or 48% less than the pipeline alternative).

**Q: ARE YOU SAYING THAT YOU KNOW THE LNG SATELLITE ALTERNATIVE IS CHEAPER ON AN ALL-IN COST PER DTH USED THAN THE PIPELINE ALTERNATIVE?**

A: Not exactly. To know about the cost of the LNG Alternative, RFPs for construction and/or leasing (as well as possibly staffing) of the facility, plus RFPs for trucked in supply should be issued, along with an internal study of staffing costs and LNG acquisition costs.

**Q: WOULD THIS LNG FACILITY BE PERMANENT?**

A: Not likely. It would instead be a temporary solution. Leaving the trailers on wheels ensures that this solution is regarded as temporary. In addition, assuming that even after energy efficiency measures are applied, the annual load from the addition of new customers grows, it would be prudent to then find a solution that would reduce gas demand (such as electrification) or a small expansion of Transco (in the range of 36,000 Dthd to 72,000 Dthd). These more permanent solutions could both meet accumulated increase in peak demand plus the peak demand expected to occur over the next few years. Then, to the extent a NPA might be needed again in the more distant future, alternatives would again be evaluated.

**Q: IS THE NON-PIPELINE ALTERNATIVE YOU PROVIDED AS AN EXAMPLE ABOVE RELEVANT TO PSNC AND ITS LIKELY PROPOSAL TO SEEK COST RECOVERY OF THE MVP/MVP SOUTHGATE PROJECTS SHOULD THEY GO IN-SERVICE?**

A: I believe so. To the extent that PSNC faces 1,500 Dth per hour of peak demand growth, this sort of non-pipeline alternative should be a relevant alternative to PSNC's MVP/MVP Southgate plans. Likewise, to the extent the total demand usage of 375,750 Dth is needed, the non-pipeline alternative sketched out above is a relevant and potentially viable alternative. However, the MVP/MVP Southgate project is not a 36,000 Dth per day project; and, thus the All-in Cost Analysis would yield a very different result from the $55.95 per Dth of use that was modeled above.

## V. <u>All-In Cost Analysis of the MVP/MVP Southgate Project</u>

**Q: HAVE YOU DONE A SIMILAR ALL-IN COST ANALYSIS OF THE MVP/MVP SOUTHGATE PROJECT?**

A: Yes. I have done a back of the envelope All-In Cost Analysis of the project, at the magnitude of PSNC's subscription to the MVP/MVP Southgate project.

**Q: PLEASE ELABORATE.**

A: First, the MVP portion of the project subscribed to by PSNC is 250,000 Dth per day and PSNC's portion of MVP Southgate is sized at 300,000 Dth per day. The 50,000 Dth per day of PSNC's MVP Southgate capacity that is greater than the Company's MVP capacity does make sense as far as meeting an existing need to firm up deliveries from East Tennessee Natural Gas/Saltville storage to PSNC facilities. Thus, I used 250,000 Dth per day for my analysis.

**Q: WHAT IS THE NEW MAXIMUM DEMAND THAT PSNC CLAIMS IT NEEDS THE MVP/MVP SOUTHGATE CAPACITY TO MEET?**

A: For my analysis of near-term cost impact, I will use the same 1,500 Dth per hour (36,000 Dth per day of pipeline capacity) that I used in my example above. I calculated this by comparing the Company's Design Day Requirements for 2022-23 to Design Day Requirements for 2020-2021 as reported in Jackson Direct, Exhibit 1. This comparison shows an increase in design day requirements of 14,856 Dth per day (after an assumed continuation of the 24,000 Dth per day of Short-Term Peaking Service into 2022-23 as PSNC shows for 2021-22) which yields a design hour (at 10% of daily in peak hour) of approximately the same 1,485.6 per hour as my modeled 1,500 Dth per hour.

**Q: WHAT ARE YOU ABLE TO CONCLUDE?**

A: The difference between my initial example and PSNC's capacity on the MVP/MVP Southgate projects is that the cost of a 250,000 Dth per day solution to a 1,500 Dth per hour and 15,000 Dth per day problem, on an All-In Cost per Dth of *use* basis, will be vastly more expensive.

**Q: DO YOU HAVE AN ESTIMATE OF THE ALL-IN COST ON A PER DTH OF USE BASIS BASED UPON THE 250,000 DTH PER DAY SOLUTION TO PSNC'S 2022-23 DESIGN DAY DEMAND INCREASE OF APPROXIMATELY 36,000 DTH PER DAY?**

A: Yes, my rough calculations result in an All-In Cost for the period (i.e., assuming the same 375,750 Dth of incremental use above existing resources -- over the winter period -- as I used in my example) to be $324.22 per Dth used. Here the incremental use is of the total demand estimated to be met by MVP/MVP Southgate for demand in excess of existing resources pre-MVP/MVP Southgate.

**Q: PLEASE EXPLAIN AGAIN WHY THE 375,750 DTH OF USE IS WHAT YOU SPREAD THE FIXED AND VARIABLE COSTS OVER?**

A: Outside of the winter period, which is the only time that sales demand may exceed PSNC's existing resources, the existing resources can meet the demand. Thus, the incremental cost is divided by the *incremental use* not met by existing facilities/resources to calculate the cost per Dth used.

**Q: CAN YOU TELL US WHAT THE TOTAL COSTS WERE THAT WHEN DIVIDED BY 375,750 DTH YIELDED THE $324.22 PER DTH USED?**

A: Yes. As I said, it is a rough estimate of the rates that MVP and MVP Southgate will charge PSNC for its capacity reservations on the two pipelines based on publicly available information. I pulled the total project cost information from MVP's and MVP Southgate's Exhibits N and P from their respective certificate applications to FERC. These exhibits identified daily reservation recourse rates of $0.9729 and $0.6170, respectively. Then, I applied a negotiated rate discount of 20% to the sum of these two as an estimate of typical negotiated rate discounts to recourse rates to arrive at a PSNC rate for the 250,000 Dth per day of common capacity (i.e., excluding the East Tennessee Natural Gas/Saltville 50,000 Dth per day on MVP Southgate) for MVP/MVP Southgate of $1.27 per Dth per day.

**Q: WHAT IS THE TOTAL MODELED ANNUAL COST FOR PSNC USING THIS $1.27 PER DTH PER DAY?**

A: Multiplying this modeled $1.27 per Dth per day times 250,000 and then multiplied by 365 equals $120,509,745 per year of fixed cost associated with MVP/MVP Southgate. Then, I divided this fixed cost by the 375,750 of incremental Dth of demand which results in a fixed cost per Dth used of $320.72. Then, adding the same modeled $3.50 per Dth of average gas cost for the gas used, we arrive at the $324.22 per Dth of incremental gas used through the 250,000 Dth per day solution. Based on my analysis, PSNC's purchase of year-round capacity on the MVP and MVP Southgate projects to meet its projected incremental demand is an extremely expensive solution to what the Company identifies as a short duration problem only occurring on the coldest winter days each year.

**Q: YOU HAVE DONE AN ALL-IN COST ANALYSIS OF TWO METHODS TO MEET INCREMENTAL DESIGN DAY DEMAND NOT MET BY EXISTING RESOURCES, SPECIFICALLY THE MVP/MVP SOUTHGATE CAPACITY ALTERNATIVE AND THE LNG ALTERNATIVE IN YOUR INITIAL EXAMPLE. ARE THOSE TWO ALTERNATIVES THE ONLY ONES AVAILABLE TO PSNC?**

A: No.

## VI. <u>Other Means of Meeting Peak Demand</u>

**Q: WHAT OTHER ALTERNATIVES DOES PSNC HAVE TO MEET ITS PROJECTED DEMAND?**

A: First of all, PSNC is currently planning to, and did during the review period, avail itself of means of meeting its design day demand other than through the combination of owned, on-system, resources (i.e., LNG vaporization) or pipeline capacity directly contracted for by PSNC (i.e., the MVP/MVP Southgate capacity). Specifically, PSNC currently plans to contract for supply from a wholesale gas merchant(s) (i.e., one or more producer(s) or marketer(s)) that holds capacity in its own name and agrees, by contract, to sell to PSNC when PSNC calls for deliveries of such contracted supply. This is generally referred to as contracting for "delivered gas" and is very common in the wholesale market, especially on pipelines where producers and marketers hold substantial capacity.

**Q: IS THE PIPELINE THAT SERVES PSNC, TRANSCONTINENTAL GAS PIPE LINE (TRANSCO) SUCH A PIPELINE?**

A: Yes. In fact, from my research of Transco's firm transportation (FT) contracts, the shippers holding such contracts, and the capacity paths of those contracts, I have determined that there is a total of 860,002 Dth per day of Transco capacity with primary path capacity flowing past PSNC that is held by merchants. This capacity is North-to-South capacity. All of this North-to-South capacity originates in Transco's Marcellus production supply area and terminates in Transco's Zone 4A in Choctaw County, Alabama.

**Q: WHAT IS THE SIGNIFICANCE OF THIS FACT?**

A: Its significance is that these shippers, if approached either by RFP or through direct negotiations, might well be willing to contract with PSNC for stated quantities both daily and over a season, that would be sold to PSNC at PSNC's existing receipt locations (a.k.a Transco delivery locations) at market prices during PSNC high demand period(s).

**Q: WHAT IF THOSE "MARKET PRICES" WERE VERY HIGH?**

A: Well, all one has to do is consider the results of the All-In Cost Analysis above, to see that PSNC would have to buy delivered gas at very inflated prices greater than $324.22 per Dth on average across an entire winter period to justify the MVP/MVP Southgate pipeline alternative. In my experience, market prices fluctuate but only very rarely get that high – and have never persisted for an entire winter period.

**Q: PSNC'S DESIGN DAY DEMAND PROJECTIONS CONTINUE TO SHOW GROWTH BEYOND THE 2022-23 PERIOD YOU ANALYZED. TO SUPPLY PROJECTED DESIGN DAY DEMAND GROWTH THROUGH SAY 2035, WHAT LEVEL OF SUPPLY RELATIVE TO THIS 860,002 DTH PER DAY OF MERCHANT-HELD CAPACITY WOULD HAVE TO BE CONTRACTED FOR BY PSNC?**

A: In 2022-23, even assuming the Short-Term Peaking Service identified by PSNC as applicable to 2021-22 was to not continue, the quantity of delivered service that PSNC would need to contract for would be about 39,000 Dth per day or 4.5% of the available merchant capacity on Transco. And, even if none of energy efficiency, electrification, nor demand response were to reduce peak day demand, and peak day demand continued to grow at 2.17% from 2022-23 to 2034-35, the resulting increase over current design day would be 297,284 Dth per day or 34.5% of available merchant capacity on Transco. In my opinion, PSNC's demand can grow at its projected rates and still be served by existing pipeline capacity at prices lower than the cost of capacity on the MVP and MVP Southgate projects.

I would further note that the states of New York and New Jersey as well as Massachusetts are targeting 2% year over year reductions in total LDC gas demand from current levels via electrification and energy efficiency. The effect on PSNC of these moves will be to potentially provide PSNC access to capacity turned back by LDCs in those states. This means that not only could existing merchant capacity be available, but PSNC access to turnback capacity from New York, New Jersey, and Massachusetts distribution companies could also be available. In addition, as the state and the nation move towards net-zero greenhouse gas emission targets and as Dominion Energy itself takes steps to meet its goal of net-zero carbon pollution by 2050,[3] the Company will likely need to take significant steps to reduce demand over the coming decades, particularly given that it has not yet explored significant available options to reduce greenhouse gas pollution from its operations, including direct air capture with carbon sequestration.[4]

In addition, I would note that PSNC currently has an annual sales load of about 53 Million Dth and an annualized year-round capacity level of 145.3 Million Dth (i.e., its firm year-round city gate capacity times 365) or uses that year-round capacity at an overall 36% load factor. In addition, PSNC has 17% load factor of its annualized 2020-21 design day to 2020-21 annual load. Using this 17% load factor, (because MVP/MVP Southgate is in PSNC's words for the coldest day), then, at a 2034-35 increased design day of 297,284 Dth per day, PSNC could contract for an additional 50,538 Dth per day of year round (possibly even turnback) capacity and maintain essentially the same usage load factor (i.e., the 17%) for the total of its year-round and peaking capacity. This would reduce delivered gas requirements from merchants in 2034-35 to 247,000 Dth per day or so and thus only 29% of merchant-held capacity.

[3] "By 2050, we will achieve net zero greenhouse gas emissions across all of our electric and natural gas operations in all 16 states where we do business. We are taking immediate action to reduce emissions as quickly as possible, while also exploring new technologies to accelerate future progress." Dominion Energy, Delivering Clean Energy, (https://www.dominionenergy.com/our-company/clean-energy).

[4] When asked to "[p]lease provide a narrative explaining the steps is PSNC taking to study or assess Direct Air Capture and subsequent sequestration or use of CO2 emitted by PSNC's natural gas customers as one way to reduce atmospheric CO2 and contribute to meeting the state's CO2 reduction goals?" PSNC responded "PSNC has not studied or assessed such steps." PSCNC's Response to Haw River Assembly's Data Request, Item 1-27(d) in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-4).

I would also note that this 50,538 Dth per day of year-round capacity in 2034-35 is quite a bit less than 250,000 Dth per day of year-round capacity as early as 2022-23.

The significance of these load factor figures is that low load factor usage of high fixed-cost year-round resources is very expensive on a per unit of use basis. Moreover, even if peak day demand were to continue to grow, from a ratepayer impact point-of-view, adding high cost year-round resources should only be considered prudent to meet peak demand if the load factor of their usage will be commensurate to or greater than current load factor usage of existing year-round resources retained to meet peak demand.

**Q: WITH RESPECT TO RELIANCE ON MERCHANT DELIVERED GAS CONTRACTS, WHAT IF THEY WORK ONE YEAR, BUT THE NEXT, THE MERCHANT DECIDES TO SELL TO SOMEONE ELSE?**

A: One way to deal with that risk would be to enter into a series of contracts extending out, respectively, for 5, 4, 3, 2 and 1 year(s); with each being for 20% of projected requirements. Then, for the one-year contract, at renewal, or going back to the market, enter into another five-year contract to cover the new (i.e., year two) design day requirement(s) for the period of the deal. And, do this at the next expiration as well so that PSNC is always covered for the next 5 years and can use that coverage to decide what and how to meet requirements in year 6 and after at any given time. In this way, PSNC and its ratepayers are not at risk for a "cliff" of expirations occurring in any "next year" and PSNC has a five-year time horizon to evaluate its load factor of usage of these contracts and whether there are more economical options to be considered for the future.

**Q: WHAT IF THOSE MERCHANT DELIVERED GAS SALES CONTRACTS HAVE RESERVATION FEES?**

A: Some level of reservation fees is not uncommon and it will be up to PSNC to evaluate such reservation fees against the cost of the gas or index/indices and expected usage to negotiate the best deals.

**Q: IS THERE ANY EVIDENCE IN THIS CASE OF PSNC HAVING FAMILIARITY WITH CONTRACTING WITH PRODUCER-MARKETER MERCHANTS FOR DELIVERED GAS SALES?**

A: Yes. PSNC has a contract with EDF (Electricte de France) a major North American merchant (See Creel Exhibit 1 Schedule 2, line 32) as an example. In addition, I researched all Transco capacity releases by PSNC collected directly from the Transco computers[5] with release periods effective during the period covered by this case. In that analysis, I found that for the November 2020 through March 2021 period, it released, under Asset Management Agreements (AMAs), 161,782 Dth per day of its Transco capacity. This figure is approximately equal to 41% of the year-round capacity figure on Jackson Exhibit 1 for Transco of 390,743 Dth per day. Contracting with merchants for 41% of winter capacity is a clear indication that PSNC is comfortable relying on merchants that hold capacity (along with likely arrangements typical under AMAs for the acquiring shipper to supply gas to the releaser when called for by the releaser, in this case PSNC).

**Q: YOU RECEIVED A DATA RESPONSE FROM PSNC WITH RESPECT TO CAPACITY RELEASES FOR THIS REVIEW PERIOD, CORRECT? DO YOUR FIGURES WITH RESPECT TO THESE AMAS MATCH THEIRS?**

[5] Skipping Stone's Capacity Center employs direct computer-to-computer electronic data interchange (EDI) to collect all capacity release data from over 100 pipelines, including Transco.

A: No. For the Winter 2020-21, PSNC indicated total Dthd released of only 82,832 Dth per day.[6] I cannot account for this difference. In preparing this testimony, my staff reviewed the Transco online bulletin board and confirmed that our EDI data for the AMA releases totaling 161,782 Dth per day (winter period) was the same as what is showing on the Transco bulletin board as released for the same winter period as of July 22, 2021.

**Q: DID PSNC PROVIDE ANY ADDITIONAL INFORMATION THAT CALLS INTO QUESTION THE REASONABLENESS OR PRUDENCE OF PSNC'S DECISION TO CONTRACT FOR FIRM PIPELINE CAPACITY FROM MVP/MVP SOUTHGATE?**

A: Yes. In a data request, we asked with respect to the capacity provided by the MVP/MVP Southgate capacity, "[w]hat market does PSNC have to absorb the approximately 250,000 Dthd (i.e., the quantity over and above the East Tennessee Natural Gas/Saltville 48,778 Dthd of winter 2022-23 "Seasonal Capacity" (see Jackson Exhibit 1)." PSNC responded that its "design day is growing by approximately 20,000 [Dth] every year."[7]

Even if its market does in fact grow at 20,000 Dth per day per year, it would take a dozen or so years (i.e., until possibly as late as 2034-35) for PSNC to grow into the 250,000 Dthd referenced in the question. And it is important to remember that the 250,000 Dthd only refers to the peak day/hour demand, leaving much of the additional firm capacity fallow much of the rest of the year. The question then becomes "Should ratepayers be 'on the hook' for this dozen

[6] PSCNC's Response to Haw River Assembly's Data Request, Item 1-17 in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-5).
[7] PSCNC's Response to Haw River Assembly's Data Request, Item 1-23(b) in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-6)

year period?", or, as I recommend above, "Should PSNC be put on notice that this level of capacity is far in excess of needs and PSNC should look to the market and not to ratepayers to support/defray this cost?"

In essence, by its own words, PSNC has told this Commission, that for years and years to come, they have (or will have) excess capacity subscribed versus their maximum modeled need.

**Q: DO YOU HAVE ANY OTHER SUPPORT FOR YOUR CONCLUSION THAT PSNC CAN RELIABLY MEET ITS PROJECTED PEAK DEMAND GROWTH IN LESS EXPENSIVE WAYS THAN BY SUBSCRIBING FOR FIRM PIPELINE CAPACITY ON THE MVP/MVP SOUTHGATE?**

A: Yes. In response to a data request about where PSNC expects "to receive deliveries off of <u>MVP directly into facilities of PSNC</u>?" PSNC responded that the Company expects to receive deliveries from the <u>Southgate lateral</u> at interconnects in Rockingham and Alamance counties.[8] In other words, PSNC will <u>*not get direct deliveries*</u> of gas from its subscription to MVP, but rather only from facilities associated with its subscription to MVP Southgate.

**Q: WHAT IS THE SIGNIFICANCE OF THAT RESPONSE?**

A: It means that PSNC could likely meet future demands by:

1) Buying gas on a delivered basis at the terminus of MVP (from a supplier with MVP capacity) and then moving it to its system "interconnects in Rockingham and Alamance counties" via MVP Southgate; or,

[8] PSCNC's Response to Haw River Assembly's Data Request, Item 1-22 in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-7).

2) Buying gas out of Southgate on a delivered basis (from one or more suppliers with MVP/MVP Southgate capacity) at its system "interconnects in Rockingham and Alamance counties"; or,

3) As noted above, buying gas on a delivered basis from existing suppliers with capacity on Transco; and

in all three cases above, doing so, only when and to the degree required, thereby avoiding the fixed costs associated with MVP and/or MVP Southgate.

This finding is consistent with my conclusion that PSNC has sufficient capacity when taking into account PSNC held contracts and available merchant capacity available to PSNC via delivered gas sales to meet it infrequent and short duration design day needs.

**Q: ARE THERE DATA RESPONSES FROM PSNC WHICH SUPPORT THIS RECOMMENDATION?**

A: One in particular does.

**Q: WHAT IS THAT ONE?**

A: In response to the request to "identify the pipeline(s), contract(s) and Path(s) that such' [Short-Tern Peaking Service LNG]' supply follows to PSNC's service area(s) location(s)," PSNC responded that it "does not determine the flow of gas or its origination under these contracts, which are for bundled peaking services to PSNC's city gate."[9]

**Q: WHICH MEANS?**

[9] PSCNC's Response to Haw River Assembly's Data Request, Item 1-19(a) in the Annual Review of Gas Costs Docket NO. G-5, SUB 635 (July 9, 2021) (Attached as Ex. GML-8).

A: Because in a confidential portion of the response to HRA 1-19, PSNC does state the parties and origination of the service, this means that PSNC has the ability; when contracting for delivered supplies, to be confident in the services' certainty enough to be able to list it as meeting is Design Day Requirements. Thus, even though PSNC may "not *determine* the flow of the gas or its origin", it does now, and can in the future, know the origin and thus assure itself of supply verity. What this means is that should PSNC contract for just the quantities and time frames it actually needs instead of incurring the fixed costs of MVP and/or MVP Southgate, it could avail itself of gas available from the MVP capacity without contracting directly with MVP for the capacity. It could even require the sellers to certify that they have the necessary firm transportation to support the sales under a delivered gas transaction.

**Q: COULD ALL-IN COST ANALYSIS BE APPLIED TO PEAK PERIOD DELIVERED GAS TRANSACTIONS AS PART OF THE APPLES-TO-APPLES COMPARISONS?**

A: Absolutely. To the extent such peak period delivered gas transactions had reservation charges, the first component of All-In Cost Analysis could be derived to identify the All-in Cost per Dth per day; and to the extent there was a stated commodity charge (or indexed commodity charge) then the estimated use of that transaction (i.e., the Dth that would be estimated to be bought by PSNC under the arrangement) would enable the calculation of the second component. I should note here that while I think the All-In Cost Analysis approach that I have described in this testimony is ideally suited to make the kind of cost-comparison that the Commission should require before accepting fixed costs of a new pipeline as prudently incurred, the broader point is that some kind of apples-to-apples comparison needs to be made to compare an expensive pipeline solution to other viable, less expensive options to meet PSNC's peak demand needs. Were the Commission to fashion its own apples-to-apples methodology, it would be important to measure the two components: (1) the cost per Dth per day (or hour) of demand to be met; and (2) the effective cost per Dth of the incremental use (i.e., the load factor of use) of the proposed means of meeting the incremental demand over the period of incremental demand not able to be met with existing resources.

## VII. <u>Estimate of Significant Increases in Costs to PSNC Sales Customers and Other PSNC Customers</u>

**Q: RETURNING TO THE POTENTIAL COSTS COMING TO PSNC SALES CUSTOMER RATEPAYERS FROM PSNC'S SUBSCRIPTION TO MVP/MVP SOUTHGATE, DO YOU HAVE AN ESTIMATE OF THE POTENTIAL IMPACT OF THOSE COSTS ON GAS COSTS AS COMPARED TO GAS COSTS IN THIS CASE?**

A: Yes, the All-In Cost Analysis related to evaluating one alternative versus other methods for meeting Design Day Demand; however, it is possible to employ some of the same analysis that enabled the All-In Cost Analysis to project impacts to ratepayers' gas costs from these same underlying Fixed Cost streams.

**Q: HOW DID YOU ESTIMATE THEM, AND WHAT DO YOU ESTIMATE THOSE PER DTH COST IMPACTS TO BE?**

A: To do this, I first took PSNC's projected design day demand growth factor year-over-year of 2.17% and applied that to total throughput of sales in this case of just under 53 Million Dth in this 2020-21 year and escalated that to 2022-23 to get a figure of just under 55 Million Dth (54,894,508 Dth in the 2022-23 gas year). Then, I divided the estimated Fixed Cost of MVP/MVP Southgate (that I derived for the All-In Cost Analysis of $120,509,745) by this approximately 55 Million Dth number and arrived at a $2.20 per Dth increase in sales ratepayer gas costs – for ***all gas sold*** to ratepayers. This equates to an increase for ***each unit*** sold by PSNC over the course of the year of $0.22 per Therm.

Comparing this to a simple, back of the envelope, view of current gas costs in this case, I took "TOTAL COMMODITY COSTS EXPENSED" of $128,838,351 (Creel Exhibit 1, Schedule 3, bottom right) and divided this by "GAS SUPPLY FOR DELIVERY" of 52,287,485 Dth (Creel Exhibit 1 Schedule 10, bottom right) to arrive at an indicative $2.45 per Dth or $0.245 per Therm. The modeled $0.22 increase discussed above would take this $0.245 per Therm to $0.465 per Therm, a near doubling of this view of gas cost[10].

**Q: DOES THIS MEAN THAT PSNC SALES CUSTOMERS WOULD BEAR ALL OF THE COSTS OF MVP/MVP SOUTHGATE?**

A: If done this way, yes. However, having read the NCUC regulations with respect to increases/decreases in demand and storage costs on PSNC's transportation rates, it is not clear from those regulations that only sales customers of PSNC will be impacted.

Pursuant to NCUC regulations R1-17-(k) Procedure for Rate Adjustments Under G.S. 62-133.4. Section 3(b), firm and interruptible transportation rates (i.e., those paid by industrial users transporting gas on PSNC) will see large increases due to MVP because "[f]irm and/or interruptible

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[10] I present this calculation in this way, because the increased costs from MVP/MVP Southgate are not yet "fixed", they are avoidable ratepayer costs and this as such, in this indicative view are presented as variable/potential increases in ratepayer costs.

transportation rates shall be computed on a per unit basis by subtracting the per unit Commodity and Other Charges included in the applicable firm or interruptible sales rate schedule from the applicable firm or interruptible rate schedule exclusive of any decrements or increments. Commodity deferred account increments or decrements shall not apply to transportation rates unless the Commission specifically directs otherwise. ***Demand and storage increments or decrements shall apply to transportation rates***." [emphasis added]

**Q: WHAT DOES THIS MEAN?**

A. Industrial customers of PSNC often use the PSNC distribution system for gas transportation only. By my reading of this language, it could very well mean that PSNC's choice to contract for MVP/MVP Southgate will also negatively impact industrial customers of PSNC by as much as the same $2.20 per transported Dth (or $0.22 per transported Therm).

Because the fixed costs of MVP/MVP Southgate would essentially double PSNC's total fixed costs as reported in this review period, by this reading of the regulations, the fixed demand cost component of transport rates could also essentially double. Nowhere in the testimony or exhibits filed by PSNC in this case did I see any calculation of, or deduction from, its fixed costs, of any fixed costs associated with transportation revenues (which also contain an allocation of fixed costs) received by PSNC from on-system transportation.

**Q: WHAT WOULD BE THE IMPACT OF THE MVP/MVP SOUTHGATE FIXED COSTS IF SUCH FIXED COSTS WERE ALLOCATED TO BOTH SALES AND TRANSPORTATION?**

A: I cannot say for certain. As PSNC witness Jackson stated, "Approximately half of the Company's throughput during the review period consisted of deliveries to industrial or large commercial customers, including electric generation, many of whom either ***purchased or transported*** gas under interruptible rate schedules." Jackson Direct, p. at 18:21 (emphasis added). Because I do not know what portion of that half of throughput was made up of "interruptible sales" versus "interruptible transport," and thus is counted in the approximately 53 Million Dth of sales, I am not able to estimate the per Dth increase in transport rates, were such an allocation of fixed costs to occur. Nevertheless, even if the $2.20 per Dth increases in 2022-23 were only half that amount, an increase in transport rates of $1.10 per Dth is a large increase in any event.

**Q: IF EITHER IMPACT WERE TO BE AFFECTED IN TRANSPORT RATES, DO YOU HAVE ANY ESTIMATE OF THE IMPACT ON ELECTRIC RATES FOR GAS DELIVERED BY PSNC USED TO GENERATE ELECTRICITY IN 2022-23?**

A: Yes. From my work related to Duke Energy in the Carolinas, I know that PSNC, at least, delivers gas to some Duke Energy power plants. A very coarse measure, using an 8,000 Btu per kW heat rate (the Btus of gas needed to generate a kW), and the $2.20 per Dth increase in the demand component of transport rates would be an increase of $17.56 per MWH or a $0.0175 per kWh for the electricity generated in North Carolina from gas delivered by PSNC.

## VIII. Conclusions and Recommendations

**Q: WHAT IS THE BOTTOM LINE FOR PSNC'S DECISION TO CONTRACT FOR CAPACITY ON THE MVP AND MVP SOUTHGATE PROJECT?**

A: My conclusion is that PSNC's decision to contract for MVP/MVP Southgate capacity not only affects firm gas customers of PSNC, but also large commercial and industrial gas users of PSNC as well as electric customers in North Carolina.

**Q: DO YOU HAVE ANY RECOMMENDATIONS FOR MEASURES THAT THE COMMISSION COULD TAKE TO MITIGATE THESE COST IMPACTS FROM PSNC'S DECISION TO CONTRACT FOR THE 250,000 OF MVP/MVP SOUTHGATE THAT YOU HAVE IDENTIFIED?**

A: Yes. In the Commission's Order approving the MVP/MVP Southgate agreements, the Commission specifically stated that it could reject the agreements and/or disallow costs associated with the contracts. In part, because there is no reasonable projection of increased demand sufficient to justify the expenditures of the magnitude that will come in the near future, that recovery should be limited.

**Q: PLEASE EXPLAIN WHY THIS IS IMPORTANT.**

A: In assessing what costs from MVP/MVP Southgate that ratepayers should be required to absorb, one way to mitigate the cost to ratepayers of this decision by PSNC would be for the Commission to put PSNC on notice, in this case, that the 250,000 Dth per day decision is far in excess of demonstrated PSNC need. The Commission should alert PSNC that it is at risk for recovery of such excess subscription. In effect, the Commission can warn PSNC that it may not be allowed recovery of dollars in excess of the All-In Cost of non-pipeline alternatives that would address PSNC's stated need. Using this measure, non-pipeline alternatives that could be benchmarked against would be like the satellite LNG alternative I discussed above or a combination of one or more of the following:

1) peaking CNG facilities,

2) expanded LNG vaporization at existing facilities,

3) energy efficiency measures,

4) demand response measures, and/or

5) electrification of heating or hot water, (to the extent the increased electrical demand can be met by increased renewables able to supply such electrified demand at the times of day that electrical demand from such electrification is forecasted to materialize).

**Q: IS THERE ANOTHER APPROACH THE COMMISSION COULD TAKE?**

A: Alternatively, the Commission could put PSNC on notice that it will only allow recovery of reservation cost of capacity associated with the lower of Commission approved increase in forecasted Design Day demand (i.e., that increase presented and approved in these gas-cost adjustment proceedings) or actual increases in peak-day demand (from that increase presented in these gas cost proceedings). In the absence of an IRP-like proceeding, these annual gas cost dockets are one of the few opportunities to raise concerns about potential imprudently incurred costs and present alternatives that could protect customers from excess costs associated with acquiring or holding capacity in excess of capacity needed to supply PSNC firm customers' demand.

**Q: ARE YOU RECOMMENDING THAT PSNC SHAREHOLDERS ABSORB ALL SUCH EXCESSIVE COSTS?**

A: In light of this recommendation as to the level of permitted recovery, I also recommend that PSNC be permitted to mitigate such costs to shareholders by being permitted to retain all secondary market revenues associated with releasing MVP and/or MVP Southgate capacity into the secondary market and/or earned from its making "bundled sales" to non-firm customers of PSNC (on or off of the PSNC system) utilizing the MVP and/or MVP Southgate facilities. This approach varies from the current practice of PSNC sharing a portion of such revenues with ratepayers. With respect to these "bundled sales," the gas sold, and the imputed margin from those sales, should be calculated as having used the most expensive gas available to PSNC at the time of the "bundled sale," thus ensuring that PSNC's firm customers are not paying more for gas supplied to them because less expensive gas available to PSNC was diverted to such "bundled sales."

In short, in light of ratepayers being fully protected against these excess costs, and should PSNC nevertheless proceed with *__not disposing__* of those costs (by means discussed below), this alternative would allow PSNC to retain secondary market revenues from releases of MVP/MVP Southgate as well as margin from bundled sales utilizing those facilities, instead of sharing those revenues with ratepayers, so as to provide shareholders a means of mitigating their costs.

**Q: IF THE COMMISSION WERE TO ADVISE PSNC AGAIN THAT IT WAS AT RISK OF NON-RECOVERY OF A LARGE PORTION OF THE MVP/MVP SOUTHGATE FIXED COSTS, IS THERE ANYTHING THAT PSNC COULD DO BETWEEN NOW AND 2022-23 TO MITIGATE THE PROBLEM ITS SHAREHOLDERS MIGHT FACE?**

A: Yes, as just alluded to, there are several. First, there are a number of shippers that had subscribed to capacity on the now cancelled Atlantic Coast Pipeline (ACP) who might be interested in purchasing MVP/MVP Southgate capacity.

Second, there are potentially producers with current or future gas production in the MVP supply area (i.e., the Southwest Pennsylvania Marcellus drilling region) looking for outlets for that supply that could take assignment of PSNC's excess capacity. Moreover, knowing now that it was at risk of non-recovery, PSNC would have the next year or more to pursue one or more such strategies. In some regards, it is not unlike PSNC's having sold off its ownership share of the MVP Southgate project to a willing buyer, and, in the case of the excess capacity, there might well be a willing, creditworthy, "buyer" of, or "assignee" for, that portion of PSNC's subscription which is in excess of near to mid-term "need".

Lastly in this regard, PSNC could assign all of its capacity and capacity-related financial obligations to a producer or marketer and offer that same entity a contract to supply delivered gas to meet PSNC's design day needs going forward.

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

A. Yes.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Gregory M. Lander on Behalf of the Haw River Assembly either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the $26^{th}$ day of June, 2021.

s/ David L. Neal

David L. Neal

## Greg Lander, President
## Skipping Stone LLC

### *Professional Summary:*

As President of Skipping Stone Inc., Greg Lander is responsible for Strategic Consulting in the mergers and acquisition arena with numerous clients within the energy industry. Generally recognized in the energy industry as an expert, he has advised and/or given testimony at numerous Federal Energy Regulatory Commission (FERC), State, arbitration, and legal proceedings on behalf of clients and has advised as well as initiated standards formation before the Gas Industry Standards Board (GISB) (predecessor to the North American Energy Standards Board (NAESB)). As Founder, President, and Chief Technology Officer of TransCapacity Limited Partnership, he was responsible for conceiving, planning, managing, and designing Transaction Coordination Systems utilizing Electronic Data Interchange (EDI) between trading partners. As a founding member of GISB, he assisted in establishing protocols and standards within the Business Practices, Interpretations and Triage Subcommittees.

### *Professional Accomplishments:*

- Handled all Due Diligence for purchaser (Loews Corp) in acquisitions of two interstate pipelines, one natural gas storage complex, and ethylene distribution and transmission systems (Texas Gas Transmission, Gulf South Pipeline, Petal Storage, Petrologistics, and Chevron Ethylene Pipeline) most in excess of $1 Billion. Developed purchaser's business case model, including rate/revenue models, forward contract renewal models, export basis modeling and revenue models, and operating cost and capex models. Coordinated Engineering and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Assisted major electric retailer in 9 states with business case development for entry into North Eastern U.S. Commercial &Industrial natural gas marketing business. Identified market share of incumbents; retail registration process, billing processes; utility data exchange rules and procedures and developed estimates of addressable market by utility.
- Handled all economic Due Diligence for purchaser of large minority stake in Southern Star Gas Pipeline. Developed purchaser's business case model, including rate/revenue models and forward contract renewal models, assessed potential competitive by-pass of asset located in "pipeline alley", developed revenue models and operating cost and capex models. Coordinated Engineering, Pipeline Integrity, and Environmental Due Diligence Teams integrating findings and assessments into final Diligence Reports.
- Developed post-acquisition integration plans for inter-operability and alterations to system operations to take advantage of opportunities presented by

synergistic facilities' locations and functions and complimentary contractual requirements. Implementation of plan resulted in fundamental changes to systems operations and improvement in systems, net revenues, capacity capabilities, and facilities utilization.

- Handled all economic analysis, modeling, and systems capability due diligence for potential purchaser in several preliminary or completed yet un-consummated pre-transaction investigations involving Panhandle Eastern, Northern Border, Bear Paw, Florida Gas, Transwestern, Great Lakes, Guardian, Midwestern, Viking, Southern Star, Columbia Gas, Midla, Targa (No. Texas), Ozark, ANR, Falcon Gas Storage, Tres Palacios, Rockies Express, Norse Pipelines, Southern Pines, Leaf River, LDH (Mont Belvieu), Kinder Morgan Interstate, Trailblazer, Rockies Express and South Carolina Gas Transmission.
- Post Texas Gas Transmission and Gulf South Pipe Line acquisitions, assisted with all investigations involving assessments and proposals for realizing potential synergies with/from asset portfolio; rate case strategy development and alternate case development; and strategies around contract renewal challenges.
- Headed up due diligence team in acquisition of multi-state retail (residential) natural gas and electric book by Commerce Energy.
- Headed up due diligence team in acquisition of multi-state retail (C&I) natural gas book by Commerce Energy.
- Served as lead consultant for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in several major FERC Rate Cases, service restructuring, and capacity allocation proceedings involving a major Southwestern U.S. Pipeline.
- Expert witness in numerous gas and electric utility rate cases; integrated resource plans; litigated service offerings and cost approval and allocation proceedings for public interest clients. Controversies, often involving hundreds of millions to billions of dollars over cases' time horizons, are common.
- Served as lead consultant and expert witness for consortium of end-users, Local Distribution Companies, Power Generators, and municipalities in major FERC rate case under litigation involving decades-long disputes over service levels, cost allocation, and rate levels.
- Served as lead consultant for consortium of end-users and municipalities in major FERC rate case involving implementation of proposed rate design, cost allocation, and rate level changes.
- Developed and critiqued Rate Case Models for several pipeline proceedings and proposed proceedings (as consultant variously to both pipeline and shippers). Activities included modeling (and critiquing) new services' rates, costs, and revenues; responsibilities included development of various alternative cost allocation/rate designs and related service delivery scenarios.

- Handled all market assessment, forward basis research, and transportation competition modeling for several proposed major pipelines and laterals, including two $1 Billion+ Greenfields projects that went into construction and operation providing new outlets for growing southwestern shale production. (Gulf Crossing and Fayetteville Lateral).
- Assessed supply and demand balance for Southwestern US (OK, TX, Gulf Coast and LA) including assessment of future demand and supply displacement associated with West Texas wind power development and its likely impact on pipeline export capacity from region.
- Assessed supply and demand balance for Northeast to Gulf Coast capacity additions including assessment of Gulf Coast demand and export growth and its likely impact on forward basis.
- Assessed start-up gas supply needs for Appalachian coal fired power plant, resulting in installation of on-site LNG storage and gasification to address lack of enough firm pipeline capacity to meet need.
- Assessed installed and projected wind-turbine capacity in ERCOT and its eventual impact on Texas electric market as wind power output approaches minimum ERCOT load levels.
- Designed and developed EDI based data collection system, data warehouse and web-based delivery system (www.capacitycenter.com) for delivering capacity data collected from pipelines to shippers, marketers, traders, and others interested in capacity information to support business operations and risk-management requirements.
- Designed pipeline capacity release deal integrating settlement system for firm users, including design and development for information services delivery on a transaction fee basis.
- Assisted client in developing proposals to increase pipeline capacity responsiveness and proposed market fixes that would create price signals around sub-day non-ratable flows, including rate proposals, sub-day capacity release markets, and measures to address advance reservation of capacity for electric generation fuel to meet sub-day generation demands.
- Developed "universal capacity contract" data model for storage of all interstate capacity contract transactions from all 60 major interstates in single database.
- Led design effort culminating in FERC-mandated datasets defining pipeline capacity rights, (including receipt capacity, mainline capacity, delivery capacity, segmentation rights, in and out of path capacity rights), Operationally Available Capacity, Index of Customers, and Transactional Capacity Reports (through GISB).
- Assembled consortium of utilities to investigate and develop large high-deliverability salt storage cavern in desert southwest (Desert Crossing). As LLC's Acting Manager, was responsible for developing business case and

economic models; handling all partner issues and reporting; coordinating all field engineering, facilities design, planning and siting; and managing all environmental, legal, engineering and regulatory activities. Wrote FERC Tariff. Brought project to NEPA Pre-Filing Stage and conducted non-binding Open Season, as well as assisted with prospective shipper negotiations. Project cancelled due to 2001 “California Energy Crisis” and contemporaneous Enron and energy trading sector implosions.

- Designed comprehensive retail energy transaction and customer acquisition data model, process flow, and transaction repository for web-based customer acquisition and customer enrollment intermediary.
- Experienced in negotiation and drafting (from both seller side and buyer side) of firm supply, firm precedent, firm transportation, firm storage, and power supply and capacity agreements for numerous entities including project financed IPPs and for new greenfields pipeline and expansion of storage system.
- Conducted interstate pipeline capacity utilization analysis for New England following winter of 2013/2014 price fly-up.
- Conducted PJM East interstate gas pipeline capacity utilization and comparative analysis between pipelines with standard NAESB nominating cycles versus those with near hourly scheduling practices.
- Conducted requirements analysis for several firms pursuing software selection of energy transaction systems.
- Instrumental in the formation of the GISB. Member of industry team that lead the development of the proposal for and bylaw changes related to the formation of NAESB.
- Provided support to numerous clients and clients’ attorneys in disputes involving capacity contracts, capacity rights allocations, tariffs, rate cases, and supply contract proceedings as both up-front and behind the scenes expert.

***Associations and Affiliations:***

Longest serving Member of Board of Directors for NAESB and prior to that GISB - 25 years.

GISB Committees: Former Chairman, Business Practices Subcommittee – drafted approximately 450+ initial industry standards that are now codified FERC regulations (Order 567); Former Chairman, Interpretations Subcommittee – drafted and led adoption process for first 50+ standards interpretations; Former Chairman, Triage Subcommittee; Title Transfer Tracking Task Force; Order 637 GISB Action Subcommittee; and industry Common Codes Subcommittee. Currently member of NAESB Wholesale Gas Quadrant Executive Committee and of NAESB Parliamentary Committee.

### ***Past and Affiliations and Associated Accomplishments:***

1981-1989: One of five initial employees of Citizens Energy Corporation, Boston Mass. Responsible for starting and growing Citizens Gas Supply, one of the first independent gas marketers of the early 1980's, into $200MM+ annual operation. Successfully lobbied for pipeline Open Access (Orders 436 and 636), introduction of pipeline Affiliated Marketer rules of conduct (Order 497), and Open Access to pipeline operational information (Order 563).

1989-1993: Independent Consultant - Natural Gas Projects, Pipeline Rate Cases, Project Financed Contract negotiations, and Independent Power markets

1993 – 1999: Founder and President, TransCapacity Service Corp – Software products and services related to pipeline capacity trading, nomination, and contracting. Raised $17 MM from industry player to establish TransCapacity. Successfully lobbied for Pipeline restructuring and formation of capacity release market (Order 636). Sold to Skipping Stone.

1999 – 2004: Principal and Partner, Skipping Stone – Energy market consultants

2004 – 2008: President of Skipping Stone following purchase of Skipping Stone by Commerce Energy, Inc.

2008: Repurchased Skipping Stone from Commerce Energy, Reformulated Skipping Stone as LLC with Peter Weigand

2008 to Present: President and Partner, Skipping Stone. In addition to handling book of clients, responsible for all Banking, Accounting, Operations, Risk Management and contract matters for Skipping Stone.

### ***Education:***

1977: Hampshire College, Amherst, MA; Bachelor of Arts

### ***Publication:***

2013: Synchronizing Gas & Power Markets - Solutions White Paper

**Expert Testimony of Gregory M. Lander**

| Name of Case | Jurisdiction | Docket Number | Date |
|---|---|---|---|
| El Paso Natural Gas Company | Federal Energy Regulatory Commission | RP04-251-000 | May 3, 2004 (Testimony) |
| El Paso Natural Gas Company | Federal Energy Regulatory Commission | RP08-426-000 | May 19, 2009 (Answering Testimony)<br><br>June 2, 2010 (Supplemental Answering Testimony) |
| El Paso Natural Gas Company | Federal Energy Regulatory Commission | RP10-1398-000 | June 28, 2011 (Answering Testimony)<br><br>March 4, 2014 (Answering Testimony) |
| Petition of Boston Gas Company and Colonial Gas Company, each d/b/a National Grid for Approval by the Department of Public Utilities for a Firm Transportation Contract with Algonquin Gas Transmission Company | Massachusetts Department of Public Utilities | 13-157 | December 12, 2013 (Direct Testimony) |
| Petition of Boston Gas Company d/b/a National Grid for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of | Massachusetts Department of Public Utilities | 15-34 | June 5, 2015 (Direct Testimony) |

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| Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project | | | |
| Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval by the Department of Public Utilities of a twenty-year Firm Transportation Agreement with Tennessee Gas Pipeline Company, involving an expansion of Tennessee's interstate pipeline running from Wright, New York to Dracut, Massachusetts, known at the Northeast Energy Direct Project | Massachusetts Department of Public Utilities | 15-39 | June 5, 2015 (Direct Testimony) |
| Petition of The Berkshire Gas Company for Approval of a Precedent Agreement with Tennessee Gas Pipeline Company, LLC, pursuant to G.L. c. 164, § 94A | Massachusetts Department of Public Utilities | 15-48 | June 5, 2015 (Direct Testimony) |
| Investigation of Parameters for Exercising Authority Pursuant to Maine Energy Cost Reduction Act, 35-A M.R.S.A. Section 1901 | Maine Public Utilities Commission | 2014-00071 | July 11, 2014 (Direct Testimony) |
| Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 *et seq*. | Virginia Corporation Commission | PUR-2017-00051 | August 11, 2017 (Direct Testimony) |

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| In the Matter of the Laclede Gas Company's Request to Increase Its Revenues for Gas Service<br><br>In the Matter of the Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenues for Gas Service | Missouri Public Service Commission | **File No. GR-2017-0215**<br><br>**File No. GR-2017-0216** | September 8, 2017 (Direct Testimony) Consolidated and November 21, 2017 (Surrebuttal Testimony) Consolidated |
| Application of San Diego Gas & Electric Company (U902M) for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2019.<br><br>Application of Southern California Gas Company (U904G) for Authority, Among Other Things, to Update its Gas Revenue Requirement and Base Rates Effective on January 1, 2019. | California Public Utilities Commission | Application 17-10-007<br><br>Application 17-10-008 | Consolidated<br><br>Direct Testimony May 14, 2018<br><br>Rebuttal Testimony June 8, 2018 |
| Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia | Virginia State Corporation Commission | PUR-2018-00067 | Direct Testimony June 14, 2018 |
| Application of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Regarding Feasibility of Incorporating Advanced Meter Data Into the Core Balancing Process | California Public Utilities Commission | Application 17-10-002 | Direct Testimony July 2, 2018 |
| Virginia Electric and Power Company's Integrated Resource Plan filing | Virginia Corporation Commission | PUR-2018-00065 | August 13, 2018 (Direct Testimony) |

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| pursuant to Va. Code § 56-597 *et seq*. | | | |
| In the Matter of Constellation Mystic Power, LLC Docket No. ER18-1639 | Federal Energy Regulatory Commission | ER18-1639 | September 4, 2018 (Cross Answering Testimony) |
| South Carolina Electric and Gas Company Application for Approval of Merger with Dominion Resources Docket Nos. 2017-370-E; 2017-305-E; and 2017-207-E | South Carolina Public Service Commission | Docket Nos. 2017-370-E; 2017-305-E; and 2017-207-E | September 24, 2018 (Direct Testimony) |
| In re: Annual Review of Base Rates for Fuel Costs of South Carolina Electric and Gas Company | South Carolina Public Service Commission | Docket 2019-2-E | March 19, 2019 (Direct Testimony) |
| Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company for Gas Service | New York Public Service Commission | Case 19-G-0066 | May 24, 2019 (Direct Testimony) |
| Application of Virginia Electric and Power Company to revise its fuel factor pursuant to VA Code § 56-249.6. | Virginia State Corporation Commission | Case No. PUR-2019-00070 | June 19, 2019 (Direct Testimony) |
| In the Matter of Annual Review of Base Rates for Fuel Costs for Duke Energy Carolinas, LLC, Increasing Residential and Non-Residential Rates | South Carolina Public Service Commission | Docket 2019-3-E | August 19, 2019 (Direct Testimony) |
| Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service | New York Public Service Commission | Case-19-0309 | August 30, 2019 (Direct Testimony) |
| Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The KeySpan | New York Public Service Commission | Case-19-0310 | August 30, 2019 (Direct Testimony) |

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|---|---|---|---|
| Gas East Corp. d/b/a National Grid for Gas Service | | | |
| Annual Review of Base Rates for Fuel Costs of Dominion Energy South Carolina, Inc. | South Carolina Public Service Commission | DOCKET NO. 2020-2-E | March 13, 2020 (Direct Testimony) March 27, 2020 (Surrebuttal Testimony) |
| APPLICATION OF VIRGINIA ELECTRIC AND POWER COMPANY *To revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia* | Virginia State Corporation Commission | Case No. PUR-2020-00031 | April 30, 2020 (Direct Testimony) |
| Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC | South Carolina Public Service Commission | DOCKET NO. 2020-1-E | May 18, 2020 (Direct Testimony) June 2, 2020 (Surrebuttal Testimony) |
| In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service | District of Columbia Public Service Commission | Formal Case No. 1162 | July 31, 2020 (Direct Testimony) |
| Annual Review of Base Rates for Fuel Costs of Duke Energy Carolinas, LLC, Increasing Residential and Non-Residential Rates | South Carolina Public Service Commission | DOCKET NO. 2020-3-E | August 14, 2020 (Direct Testimony) |
| | | | |

Exhibit: GML-3
Docket No. G-5, Sub 635



**PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.**
**ANNUAL REVIEW OF GAS COSTS DOCKET NO. G-5, SUB 635**
**HAW RIVER ASSEMBLY DATA REQUEST NO. 1**
**July 9, 2021**

1-29. Assuming, as PSNC states, that 50,000 Dthd of Southgate "firms up" PSNC's ability to receive firm service to support its ETNG/Saltville storage deliverability, this would leave 250,000 Dthd of capacity on MVP/SG to serve PSNC system demand. Further, assuming that PSNC's Annual load also increases at the same 2.17% compounded year over year as its Design Day is forecasted to grow and thus becomes approximately 54.9 Million Dth in 2023; does PSNC have a market for, or an off-take buyer for, the estimated 97.5% of annual capacity (beyond PSNC's load growth) that is available to PSNC as a result of adding 91.25 Million Dth of annual capacity but forecasted to only use approximately 2.3 Million Dth of that capacity to serve PSNC's load estimated to grow at 2.17% compounded from 2021?

<u>Response</u>
The question incorrectly assumes that PSNC acquires capacity to meet the annual needs of its customers. Rather, the capacity is maintained at a level to meet PSNC's firm demand on the coldest day to ensure reliable service to firm sales customers.

**PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.**
**ANNUAL REVIEW OF GAS COSTS DOCKET NO. G-5, SUB 635**
**HAW RIVER ASSEMBLY DATA REQUEST NO. 1**
**July 9, 2021**

1-27. With respect to North Carolina's Clean Energy Plan:

a. Please provide a narrative explaining the steps is PSNC taking to access, promote and utilize:
    i. Landfill natural gas?
    ii. Biologic methane gas recovered from animal waste?
    iii. Biologic methane gas from sewage wastewater?
    iv. Other renewable sources of methane gas that have low or negative carbon intensity characteristics?

b. Please provide the daily and annual amount in Dth of the gas purchased or produced by PSNC of:
    i. Landfill natural gas?
    ii. Biologic methane gas recovered from animal waste?
    iii. Biologic methane gas from sewage wastewater?
    iv. Other renewable sources of methane gas that have low or negative carbon intensity characteristics?

c. Please provide a narrative explaining the steps is PSNC taking to reduce emissions of natural gas from its assets relative to Dominion Energy's announced goal of a 50% reduction by 2030?
    i. In this regard, is the (222,989) Dth of Company Use gas shown on Creel Exhibit 1, Schedule 10, page 2 inclusive of "lost and unaccounted for"?
        1. If so, what does PSNC estimate is the portion of the (222,989) is comprised of "lost and unaccounted for"?
        2. If not, what is the estimated amount, annually of emissions from PSNC assets that is proposed to be reduced by 50%?
    ii. In this regard, what is the dollar amount that PSNC estimates will be the annual cost between 2021 and 2030 (stated individually) of reducing emissions from PSNC assets by 50% to be?

d. Please provide a narrative explaining the steps is PSNC taking to study or assess Direct Air Capture and subsequent sequestration or use of CO2 emitted by PSNC's natural gas customers as one way to reduce atmospheric CO2 and contribute to meeting the state's CO2 reduction goals?

Response

a. PSNC has welcomed inquiries of interest from potential renewable natural gas (RNG) producers located on PSNC's system and has worked with these potential producers by providing guidance on the regulatory process, assessing the viability of interconnection points, and providing estimated costs of interconnection.

   i. Discussions referenced above have resulted in two landfill producers filing for and receiving acceptance into PSNC's pilot RNG program. Interconnection agreements were approved by the Commission for these projects.

   ii. PSNC has had inquiries and discussions with potential providers of RNG recovered from animal waste, but these potential projects are still in the conceptual stage and may or may not result in a viable project.

   iii. PSNC has had inquiries and discussions with municipal operators of sewage treatment facilities, and one operator, the City of Raleigh, has publicly announced its project.

   iv. PSNC has had inquiries and discussions with breweries, but these potential projects are still in the conceptual stage and may or may not result in a viable project.

b. PSNC has not purchased or produced any RNG.

c. Steps PSNC has taken to reduce natural gas emissions include the following:

- Broad utilization of tapping and stopping to minimize blowdown segment length and volume.
- Utilizing the pipeline system to draw down system pressures before blowdown events.
- Utilizing portable compression equipment to minimize or eliminate blowdowns. This allows gas to be moved from an isolated pipeline segment into the adjacent pipeline, keeping all the gas inside the pipe.
- Utilization of supplemental leak detection and repair surveys to reduce fugitive emissions. These surveys are performed in addition to and/or more frequently than surveys required by regulation.
- Utilization of pressurized holds at compressor stations during non-operating periods. It is common practice to blowdown compressor units when they shut down after a period of use. Leaving the compressor pressurized when not operating eliminates numerous large volume blowdown events each year.
- Investing in sustainability research via the Company's membership in Operations Technology Development, the non- profit research arm of the Gas Technology Institute.

- Implementation of a third-party damage reduction strategy that includes the addition of damage prevention specialist roles, which places a full-time focus on damage prevention efforts, and development of a high-risk ticket and excavator monitoring system.

ii. The Company Use Volumes shown on Creel Direct Exhibit 1, Schedule 10, page 2, does not include lost and unaccounted for gas. PSNC has made no estimate regarding annual emission reductions from PSNC assets.

iii. PSNC has made no estimate regarding annual cost of emission reductions.

d. PSNC has not studied or assessed such steps.

**PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.**
**ANNUAL REVIEW OF GAS COSTS DOCKET NO. G-5, SUB 635**
**HAW RIVER ASSEMBLY DATA REQUEST NO. 1**
**July 9, 2021**

1-17. For all Transco capacity releases from PSNC to acquiring shippers, please identify and provide in excel format those transactions between:

a. PSNC and affiliates of PSNC

   i. And for each such transaction please provide the OFFER Number and Bid number, the tariff rate paid by PSNC and the award rate paid by the acquiring shipper.

b. PSNC and non-affiliated electric generators

   i. And for each such transaction please provide the OFFER Number and Bid number, the tariff rate paid by PSNC and the award rate paid by the acquiring shipper.

Response

a. During the review period, PSNC did not release any capacity to an affiliate.

a. See attached Response 1-17 for all active releases of Transco capacity during the period April 2020 through March 2021.

Exhibit: GML-6
Docket No. G-5, Sub 635



**PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.**
**ANNUAL REVIEW OF GAS COSTS DOCKET NO. G-5, SUB 635**
**HAW RIVER ASSEMBLY DATA REQUEST NO. 1**
**July 9, 2021**

1-23. With respect to Jackson Direct Testimony at page 12 Ln 16 through page 13 Ln 20; and, as regards Southgate:

a. Where does PSNC expect to receive deliveries off of Southgate directly into facilities of PSNC?

b. What market does PSNC have to absorb the approximately 250,000 Dthd (i.e., the quantity over and above the ETNG/Saltville 48,778 Dthd of winter 2022-23 "Seasonal Capacity" (see Jackson Exhibit 1).

Response

a. See the response to question 1-22 above.

b. PSNC's design day is growing by approximately 20,000 dts every year. During the upcoming winter season, PSNC will need to contract for 60,000 dts/day of winter peaking supply to maintain an estimated 1% reserve margin. PSNC will have an estimated 17.9% reserve margin when the Southgate capacity goes into service in 2023; however, based on projected load growth, PSNC's estimated reserve margin will be down to 1.4% by 2030.

Exhibit: GML-7
Docket No. G-5, Sub 635





**PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.**
**ANNUAL REVIEW OF GAS COSTS DOCKET NO. G-5, SUB 635**
**HAW RIVER ASSEMBLY DATA REQUEST NO. 1**
**July 9, 2021**

1-22. With respect to Jackson Direct Testimony page 12 Ln 16 through page 13 Ln 20; and, as regards MVP; where does PSNC expect to receive deliveries off of MVP directly into facilities of PSNC?

Response

PSNC expects to receive deliveries off MVP's Southgate lateral at interconnects in Rockingham and Alamance Counties.

**PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.
ANNUAL REVIEW OF GAS COSTS DOCKET NO. G-5, SUB 635
HAW RIVER ASSEMBLY DATA REQUEST NO. 1
July 9, 2021**

1-19. With respect to Jackson Exhibit 1, please identify the entity(ies) and location(s) from which the supply is made available to PSNC for the "Short-Term Peaking Service LNG" listed under "Peaking Capacity" for both of "2020-21" (i.e., 40,000 Dth/day) and "2021-22" (i.e., 24,000 Dth/day); and with respect to same:

a. Please identify the pipeline(s), contract(s) and Path(s) such supply follows to PSNC's service area(s) location(s).

<u>Response</u>

**[BEGIN CONFIDENTIAL] …. [END CONFIDENTIAL]**

a. PSNC does not determine the flow of gas or its origination under these contracts, which are for bundled peaking services with deliveries to PSNC's city gate.