Matthew M. Weissman
General State Regulatory Counsel

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
tel: 973-430-7052 fax: 973-430-5983
email: matthew.weissman@pseg.com

PSEG
Services Corporation

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VIA ELECTRONIC DELIVERY & OVERNIGHT MAIL

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
44 S. Clinton Avenue, 9th Floor
P.O. Box 350
Trenton, New Jersey 08625-0350

Re: In the Matter of the Exploration of Gas Capacity and Related Issues, Docket No. GO19070846

Dear Ms. Camacho-Welch:

Public Service Enterprise Group, Inc. ("PSEG"), on behalf of its subsidiaries Public Service Electric and Gas Company ("PSE&G") and PSEG Energy Resources & Trade LLC ("ER&T"), PSE&G's supplier of natural gas pipeline and storage services, appreciates the opportunity to provide comments on the issues addressed in the above-referenced proceeding.

The New Jersey Board of Public Utilities ("Board") has commenced this proceeding to address two specific issues: (1) "whether sufficient capacity has been secured to serve all of New Jersey's firm natural gas customers", and (2) "whether and to what extent TPSs are saving customers' money on their natural gas supply."[1] We commend the Board and Staff for raising the important gas supply questions posed in this proceeding, both of which should be fully vetted in this process, and we look forward to taking part in this timely inquiry.

In these comments, we will discuss the state of the natural gas market in New Jersey and the role of natural gas, as well other important fuel sources, in supporting the achievement of New Jersey's energy and emissions goals, which are set forth in the State's draft Energy Master Plan and elsewhere. We then provide responses to specific questions raised by Board Staff during the initial stakeholder meeting in this matter, conducted on October 1, 2019. Finally, we provide responses to the questions set forth in the Notice issued by the Board Secretary, dated September 10, 2019, in this proceeding.

[1] I/M/O the Verified Petition of the Retail Energy Supply Association ("RESA") to Reopen the Provision of Basic Gas Supply Service, et seq., Docket No. G017121241, Decision and Order (February 27, 2019) (closing the proceeding commenced by the RESA petition, and directing staff to open this stakeholder proceeding).

PSE&G and the New Jersey Natural Gas Market

PSE&G serves over 1.8 million natural gas customers throughout its service territory within the state of New Jersey. The large majority of these customers are residential and other high priority customers that receive firm service from PSE&G and rely on PSE&G to meet their natural gas needs on an hourly and daily basis throughout the year. In fact, in New Jersey as a whole, approximately 75% of residential households are served by natural gas and rely on natural gas to meet their heating needs, particularly on peak winter days. PSE&G, like the other New Jersey gas distribution companies ("GDCs"), has a statutory obligation to ensure the adequacy of gas supplies and associated pipeline capacity to serve these high priority customers. In addition, PSE&G, like the other New Jersey GDCs, is also obligated to serve as the provider of last resort for customers who may be served by a Third Party Supplier ("TPS") and do not currently receive default commodity service, referred to as Basic Gas Supply Service or "BGSS".

In addition to the significant firm residential heating loads served by natural gas in New Jersey, use of natural gas for electric generation has become increasingly important to the state's economic well-being. The Draft 2019 Energy Master Plan ("Draft EMP") characterizes natural gas burned in state-of-the-art electric generation plants as "an important transition, or 'bridge' fuel that has helped wean the state off the heaviest polluting fuels, like coal . . . ."[2] As also recognized in the Draft EMP, the transition from other fuel sources to natural gas has led to a lower emissions portfolio, while also lowering the overall cost of energy. PSEG has lowered its greenhouse gas emissions in 2018 by 45% from 2005 levels, in part by building and operating clean and efficient natural gas power plants in lieu of coal-fired power plants. And the combined monthly electric and gas bill paid by PSE&G's typical residential customer has declined by approximately 30% since 2008, 40% when inflation is taken into account.

In light of New Jersey's clear commitment to overall reductions in energy use, significantly reduced emissions, and maintenance of reasonable energy prices, consideration of natural gas supply adequacy is an important piece of the puzzle, along with other key elements of New Jersey's energy strategy. There can no dispute that the cheapest (and cleanest) megawatt or therm of energy is the one that is never consumed in the first place, and energy efficiency efforts should continue to be paramount. There are strong economic and environmental drivers to electrify certain sectors of the economy that currently operate solely on high-emissions fossil fuels, in particular the transportation sector, where a dramatic shift from gasoline-fueled to electric vehicles is within reach and should be accelerated. That electrification effort (and the underlying economic and environmental benefits) will depend, in part, on the continued operation of New Jersey's fleet of nuclear power plants. Thus, PSEG supports the Board's implementation of the Zero Emissions Certificate ("ZEC") program, and the state's commitment to preserving the significant amount of emissions-free electricity to be generated by the state's nuclear power plants in the decades to come.

However, as New Jersey focuses on the most cost-effective means to achieve cleaner air and reasonably priced electricity through energy efficiency, strategic electrification, and preservation of zero-emissions nuclear generation, continued availability of reliable, reasonably-priced natural gas supplies is a requirement, not an option. Indeed, there are significant risks to

[2] Draft EMP, at 43.

assuming New Jersey can simply phase out the use of this plentiful, cost-effective resource, ignore real near-term and mid-term supply constraints, and neglect the extensive natural gas transmission and distribution infrastructure in place.

Consideration of the supply profile in this part of the country underscores the seriousness of the issue. As the Board is aware, extensive regional concerns have recently arisen regarding the adequacy of gas supply. These concerns began in New England several years ago and have now spread to the New Jersey and New York market areas as the development of several significant pipeline projects designed to provide incremental gas capacity to meet growing peak day needs have been delayed. In January of this year, the governor of Rhode Island declared a state of emergency after National Grid suspended natural gas service to 7,100 customers on a night with temperatures in the single digits. Also in January of this year, moratoriums were adopted by both Con Edison in their Westchester service territory and National Grid in their Brooklyn service territory, suspending natural gas service to new customers. In New York, where National Grid provides gas to 1.8 million customers in Brooklyn, Queens, Staten Island and Long Island, the utility announced earlier this year that it would not process any new applications for gas service, pending approval of the highly contested Transco Northeast Supply Enhancement pipeline project. Similar pressures in New Jersey with respect to the PennEast Project present significant challenges to New Jersey GDCs attempting to add supply diversity and satisfy their statutory obligation to acquire sufficient capacity to meet their BGSS requirements. These two projects alone represent 1.5 Bcf/day of new incremental capacity designed to meet the growing peak day needs of several GDCs, a significant addition to the total gas market requirements of this region.

Further, while New Jersey has been able to meet recent cold weather challenges such as the 2014 "Solar Vortex" and the 2017/2018 "Bomb Cyclone," these achievements are not grounds to become complacent. For example, during the "Bomb Cyclone" event that occurred from December 27, 2017, through January 8, 2018, the eastern portion of the United States experienced extremely cold temperatures and high electric demand. During this time, there were proportionally high outage levels experienced by gas-fired generators due in many cases to gas supply issues.[3] Moreover, the situation could have been worse had the cold spell lasted much longer. During this period, PSEG Power ran its dual-fuel, combined cycle generating fleet almost entirely on oil. However, despite efforts to replenish the oil tank drawdowns, certain large generators within the PSEG Power fleet were within hours of running out of oil and it is unclear whether gas could have been procured for them through the market had the cold weather conditions persisted.

As addressed below in PSE&G's responses to the specific questions in this proceeding, while PSE&G has been successful in obtaining adequate incremental pipeline capacity to meet its growing peak day requirements over the short term (2019 – 2021), it currently does not have

[3] See "PJM Cold Snap Performance: Dec. 28, 2017 to Jan. 7, 2018," pp. 16-17, Figure 15 ("Gas supply issues were the largest in this assessment [depicted in Figure 15], particularly the weekend of Jan. 6 and Jan. 7, as temperatures reached their lowest points and pipeline capacity restrictions of varying degrees were in place across all pipelines serving PJM generation. PJM uses 'gas supply issue' to refer to a generator outage that was due to lack of natural gas fuel supply, which could be due to a number of varying circumstances. Gas supply issues include transportation restrictions and interruptions as well as spot gas commodity availability.") (available at https://www.pjm.com/~/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx).

sufficient pipeline capacity to meet its requirements for 2022 and beyond. It is critical that PSE&G, like other New Jersey GDCs, be able to secure sufficient additional pipeline capacity to satisfy their statutory obligation to meet their firm gas customers' needs. Not doing so is simply not an option. Further aggravating these pipeline capacity concerns is the potential restrictions that may be imposed this winter by both Texas Eastern and Algonquin on portions of their pipeline systems that serve the New Jersey market, as well as the recent rulemaking by Pipeline and Hazardous Materials Safety Administration ("PHMSA"), providing for more stringent pipeline integrity and inspection requirements and, therefore, more pipeline maintenance and service limitations.[4]

Responses to Board Staff Questions Raised at the October 1, 2019 Stakeholder Meeting

At the October 1, 2019 stakeholder meeting Board staff posed two questions to PSE&G in particular. Responses are provided below.

Are discounts available for entities that purchase larger volumes of pipeline capacity?

Pipelines do not offer discounts based upon the size of the capacity commitment made to the pipeline. Since all interstate pipelines are subject to FERC regulation, pipelines must offer their rates and services on a non-discriminatory basis to all customers. For new pipeline capacity projects, pipelines offer capacity to the market through an "Open Season" for a certain period of time (typically a month) whereby market participants can bid for capacity on the project.[5] All bidders, regardless of the volume they bid, are offered the same choice of recourse rates (i.e., FERC cost of service-based rates that are subject to change during the term of the project), or negotiated rates, which tend to be somewhat lower than the recourse rate, but are not subject to change over the term. By way of example, two recent Transco projects in New Jersey -- Rivervale South and Gateway -- both resulted in capacity purchases by two customers, one with a large capacity commitment and the other with a small capacity commitment. In both cases, both shippers agreed to pay negotiated rates at identical levels.[6]

[4] See Final Rule, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments", PHMSA Docket 2011-0023, 84 FR 52180 (October 1, 2019) (final rule addressing integrity management requirements and other requirements focusing on, among other things, the actions an operator must take to reconfirm the maximum allowable operating pressure of previously untested natural gas transmission pipelines and pipelines lacking certain material or operational records, the periodic assessment of pipelines in certain populated areas, and related reporting and recordkeeping provisions).

[5] The term "open season" generally refers to a period of time when all parties are given equal consideration. Also, when a company becomes an open access transporter, it is generally expected to have an "open season" to accept bids for transportation. During that time all shippers are treated equally in the queue for service, with space divided on a pro rata basis. After the open season is over, shippers are generally treated on a first-come, first-served basis

[6] See FERC Docket No. CP18-18 (FERC certificate issued December 12, 2018) (approving identical rates for anchor shipper PSEG, with maximum daily quantity ("MDQ") of 54,000 dekatherms per day, and open season participant UGI, with MDQ of 11,000 dekatherms per day); FERC Docket No. CP17-490 (FERC certificate issued August 10, 2018) (approving identical rates for Direct Energy, with MDQ of 187,000 dekatherms per day, and UGI, with MDQ of 2,500 dekatherms per day).

How do the GDCs estimate the TPS for planning purposes?

As explained in more detail below in response to the Board's Notice Questions, PSE&G estimates the TPS supply that it expects to be delivered to the PSE&G system for planning purposes based upon the January TPS Daily Contract Quantity. The Daily Contract Quantity represents firm supply projected to be delivered by the TPS on a January day.

Answers to the BPU Notice Questions

The following are PSE&G's responses to the specific questions asked by the Board in its September 10, 2019 Notice in this Stakeholder Proceeding. PSE&G has not provided answers to questions # 2 or # 6 as they pertain to TPS supply, capacity and price information not available to PSE&G.

Question 1. GDC Capacity Procurement:

a. Does each GDC, (either independently or through a contract with an affiliated company) have sufficient firm capacity secured to meet their current design day forecasts for the next five years?

While PSE&G does have sufficient firm capacity secured to meet its current design day forecast for winters 2019/2020 and 2020/2021, it does not have sufficient firm capacity secured for winters 2021/2022, 2022/2023 and 2023/2024. As a result, the Company is currently exploring options to obtain additional firm capacity to meet its projected peak day requirements in those years.

b. What is the weighted average cost of the transportation and storage capacity that each of the GDCs has secured?

The weighted average cost of the transportation and storage capacity that PSE&G has secured has fluctuated in recent years due to base rate changes implemented by Transco and Enbridge. Since 2016 this cost has varied from approximately $1.49 per dekatherm to approximately $1.85 per dekatherm.

c. What assumptions does each GDC make and reflect in its forecasts about the switching of customers to and from TPSs?

Projected migration from PSE&G's BGSS service to TPS service is based on previous trends and incorporates known differences. Monthly switching data (by rate class) to and from TPSs is trended and analyzed. While switching by customers on PSE&G's RSG (residential) and GSG tariffs is more likely to follow historical trends, switching by LVG (larger commercial and industrial) customers is more volatile and challenging to predict due to changing market conditions and marketer behavior. Any known future customer switches are reflected in forecasted data, and incorporated into the Company's Peak Day forecasts and therefore accounted for in the Company's gas supply planning.

d. How does the switching of customers to and from TPSs affect each GDC's capacity portfolio?

PSE&G's capacity portfolio is designed to meet the forecasted PSE&G supply obligation to provide BGSS service, incremental load of TPS customers above required TPS deliveries, and an appropriate risk reserve. PSE&G does not maintain any firm capacity to serve the full TPS customer load on its system, as the cost of maintaining that capacity would unfairly burden PSE&G's BGSS customers to the benefit of the TPSs. To meet total utility demand, PSE&G relies on TPSs to deliver the estimated needs of their customers on a firm basis. As previously stated, while PSE&G does have sufficient firm capacity secured to meet its current design day forecast for winters 2019/2020 and 2020/2021, it does not have sufficient firm capacity secured for winters 2021/2022, 2022/2023 and 2023/2024. As customers switch from TPSs back to PSE&G, the projected design day deficiency increases. The inverse occurs when customers switch from PSE&G to TPSs. Both scenarios may require incremental purchases or sales at prices negatively impacting the BGSS customer.

Question 2. TPS Capacity Procurement

PSE&G is not providing a response to this question. Questions 2a through 2f pertain to the natural gas supply planning and operational characteristics of TPSs conducting business in New Jersey. These questions are not pertinent to PSE&G, which is a gas distribution company that provides Basic Gas Supply Service ("BGSS").

Question 3. Does sufficient pipeline capacity exist within the New Jersey market to satisfy the total customers' requirements currently served by both TPSs and GDCs? Can additional incremental pipeline capacity be obtained to meet the forecasted customer requirements over the next five years? Would this capacity be more expensive than the current capacity?

The design day forecasts submitted by the GDCs in their respective BGSS filings support the position that the New Jersey GDCs do not currently have sufficient firm pipeline capacity to be able to reliably meet their respective BGSS design day loads over a five year time horizon. The BPU and New Jersey Division of Rate Counsel already review the appropriateness of each respective BGSS capacity portfolio on an annual basis.

Historically, TPSs have generally met the required supply obligation of their PSE&G customers. However, it is uncertain as to whether the TPS obligation has been met with firm supply or can be met for a design day. Without the knowledge of TPSs' existing firm pipeline capacity to New Jersey GDCs and New Jersey GDC requirements, it is not possible to determine if sufficient pipeline capacity exists within the New Jersey market to satisfy the total customers' requirements currently served by both TPSs and GDCs.

Based on recent discussions, pipeline developers are willing to provide additional capacity to meet forecasted customer requirements over the next five years (at costs for like capacity greater than the cost of current capacity). Despite developer willingness, challenges in obtaining necessary federal and state approvals and permits make future pipeline expansion in New Jersey less likely, and will present greater challenges in the GDCs' ability to acquire additional peak day pipeline capacity to meet their growing peak day requirements.

Question 4. If the GDCs were made responsible for securing the incremental capacity for the transportation customers, what would be the costs involved and how should they be allocated? What would be the impact of those costs on BGSS customers?

The existing BGSS construct has been operating extremely well alongside a highly functioning, mature, competitive natural gas marketplace in New Jersey. The Board has established mechanisms to ensure that customers are receiving their supply of natural gas at a reasonable, market-based cost and a high level of reliability, while also not limiting the ability of customers to identify, switch to, and be served by TPSs. A robust competitive retail gas market was developed in New Jersey many years ago, and suppliers have been able to source supply and reliably deliver gas for firm customers through the years.

Requiring the GDCs to secure incremental capacity to serve all TPS customer load, if TPSs already own capacity assets, could result in the duplication of capacity assets. In addition, if GDCs were made responsible to secure incremental natural gas capacity to serve the TPS customer load at current market prices, it would increase costs to BGSS customers for the financial benefit of the TPSs with no requirement that the TPSs pass on that benefit to their customers. Even if incremental costs were to be allocated to the TPSs, the undue risks associated with term requirements (likely up to a 15 year commitment for new capacity) would be borne solely by the BGSS customer. In the event one or more TPS were to reduce its customer load, or decide to leave the market, the GDC would be left with excess capacity at a price in excess of the market price and those costs would be borne by the BGSS customers. Though PSEG does not think it is appropriate to burden BGSS customers with these incremental costs, it does support the Board's initiative to understand the rates that TPSs are charging residential customers, and the amount of money TPS-served customers are saving over the GDCs' default service rates, and believes it is important that this be evaluated in this stakeholder's process. From a policy perspective, if the Board were to consider requiring GDCs to be the source of incremental capacity for all customers, it would be imperative to understand if the result of this requirement were at least providing a savings to some customers (while costs are being borne by others).

It should also be noted that, as previously stated, there is no volume discount for a GDC buying additional natural gas capacity. GDCs would pay the same prices for firm capacity that TPSs would pay for firm capacity if the TPSs participated in the natural gas capacity market.

Question 5. If some of the TPSs have secured long term capacity for their customers, how would an allocation of capacity costs from the GDCs affect them? Would the GDCs be in a position where they would be buying capacity from the TPSs if the GDCs were required to secure capacity for transportation customers?

GDCs do not charge TPS customers for supply or pipeline costs. The GDCs charge TPS customers for balancing, which is provided to them as a service. All demand charges and transportation charges billed to TPS customers are related to distribution services, not upstream supply or pipeline charges.

As previously stated in response to question 4, if GDCs were made responsible to secure incremental natural gas capacity to serve the TPS customer load at current market prices and release capacity on a monthly basis to the TPSs, it would increase costs to BGSS customers for the financial benefit of the TPSs with no requirement that the TPSs pass on that benefit to their customers. Even if incremental costs were to be allocated to the TPSs, the undue risks associated with term requirements (likely up to a 15 year commitment for new capacity) would be borne solely by the BGSS customer.

Question 6. What rates have the TPSs charged residential customers over the past three years? How does this compare to what these residential customers would have paid for their natural gas supply if they had been served by their GDC? Did these residential customers save money? Should the TPSs be required to report pricing information to the Board and publically disclose their prices on a monthly basis?

This question is not pertinent to PSE&G, which is a gas distribution company that provides BGSS.

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Once again, PSEG commends the Board for conducting this stakeholder proceeding and appreciates the opportunity to submit comments. We look forward to continuing to work with the Board and all stakeholders on these important issues. We thank the Board for its consideration of our submission.

Respectfully submitted,

Matthew M. Weissman