**BEFORE THE**

**GEORGIA PUBLIC SERVICE COMMISSION**

**PRE-FILED DIRECT TESTIMONY OF**

**GREGORY BECKER ON BEHALF OF**

**ATLANTA GAS LIGHT COMPANY**

**DOCKET NO. 56177**

**Q.** **Please state your name, title and whom you represent.**

A. My name is Gregory Becker. I am Director, Capacity Planning for Southern Company Gas. I am testifying on behalf of Atlanta Gas Light Company (“AGL” or the “Company”) in support of the Capacity Supply Plan (the “Plan” or “CSP”) for 2025-2028.

**Q.** **Please state your educational and professional background.**

A. I have included with this testimony Attachment A, which contains a summary of my educational background and professional experience.

**Q.** **Mr. Becker, have you testified before the Georgia Public Service Commission (“Commission”) in prior dockets?**

A. Yes. I have testified in support of the Company’s last five CSPs: Docket No. 31491, Atlanta Gas Light Company’s 2010-2013 Capacity Supply Plan; Docket No. 36792, Atlanta Gas Light Company’s 2013-2016 Capacity Supply Plan; Docket No. 40287, Atlanta Gas Light Company’s 2016-2019 Capacity Supply Plan; Docket No. 42317, Atlanta Gas Light Company’s 2019-2022 Capacity Supply Plan; and Docket No. 44319, Atlanta Gas Light Company’s 2022-2025 Capacity Supply Plan. In addition, I have also testified in Docket No. 43820, Atlanta Gas Light Company’s 2022-2031 Integrated Capacity and Delivery Plan; and Docket No. 43820, Atlanta Gas Light Company’s 2024-2033 Integrated Capacity and Delivery Plan.

**Q.** **Do you sponsor any schedules included with the filing?**

A. Yes, I sponsor the Commission-required Minimum Filing Requirements (“MFRs”) schedules, included in AGL Exhibit No. \_\_\_\_ (GB-2) (Trade Secret).

**Q.** **Do you sponsor any other exhibits to your testimony?**

A. Yes, the full list of exhibits to my testimony is as follows:

* AGL Exhibit No. \_\_\_\_ (GB-1) (Trade Secret), Array of Interstate Capacity Assets (the “Array”);
* AGL Exhibit No. \_\_\_\_ (GB-2) (Trade Secret), the Minimum Filing Requirements;
* AGL Exhibit No. \_\_\_\_ (GB-3) (Trade Secret), Design Day Load Forecast;
* AGL Exhibit No. \_\_\_\_ (GB-4) (Trade Secret), Resource Summary;
* AGL Exhibit No. \_\_\_\_ (GB-5) (Trade Secret), 36-Month Resource Schedule; and
* AGL Exhibit No. \_\_\_\_ (GB-6) (Trade Secret), 9-Year Outlook.

**Q.** **Were these exhibits prepared by you or under your direct supervision?**

A. Yes, and they are true and correct to the best of my knowledge and belief.

**Q.** **What is the purpose of your testimony?**

A. My testimony describes and supports the Company’s 2025-2028 CSP. The Company asks the Commission to approve the 2025-2028 CSP as filed.

**Q.** **How is your testimony organized?**

A. My testimony has 4 main areas. The first section discusses the relationship of AGL’s 2025-2028 CSP and AGL’s 2024-2033 Integrated Capacity and Delivery Plan (“i-CDP”). Specifically, this section discusses AGL’s ongoing expansion of the Company’s Cherokee Liquefied Natural Gas (“LNG”) peak shaving plant within the timeframe of this 2025-2028 CSP. The second section focuses on the details of the 2025-2028 CSP and demonstrates that it fully complies with all applicable statutes, regulations, and other Commission requirements. The third section provides an outlook for the period beyond the 2025-2028 CSP. Finally, the fourth section addresses additional operational issues.

**I.** **The 2025-2028 CSP and the 2024-2033 i-CDP**

**Q.** **What is the primary purpose of the Company’s i-CDP planning process?**

A. Each i-CDP provides a single, comprehensive planning and review process in which the parameters for subsequent CSPs, Georgia Rate Adjustment Mechanisms (“GRAMs”), and System Reinforcement Riders (“SRRs” as a ratemaking process within each i-CDP) can be established. The second i-CDP was approved in Docket No. 43820 for the planning period covering 2024-2033. As was contemplated in the development of the i-CDP filings, each new plan is filed every three years to update forecasted interstate and intrastate capacity needs and to project needed capital and related O&M spending to effectively and efficiently meet the growing need for service to our customers.

**Q.** **How does the 2024-2033 i-CDP the Commission approved in Docket No. 43820 relate to this CSP?**

A. Each i-CDP provides a 10-year outlook for interstate, intrastate, and distribution capacity asset requirements. Each CSP offers a more detailed and refined look at the immediate three-year time period, and specifically addresses the duties of an Electing Distribution Company (“EDC”) to file, and the responsibilities of this Commission to approve, a plan for acquiring and contracting for the interstate capacity assets necessary for gas to be made available for firm distribution services. Those responsibilities are set forth in section 46-4-155(e) of the Georgia Code. Nothing in the i-CDP process replaced or diminished the requirements for the CSP process.

This 2025-2028 CSP covers the three-year period from October 1, 2025, through September 30, 2028. In this 2025-2028 CSP, the Company: (a) specifies the range of requirements to be supplied by interstate assets, to meet the projected natural gas demand of the system’s firm customers; (b) describes the Array selected by AGL to meet such requirements; (c) describes the criteria for AGL to enter into contracts under such Array; and (d) specifies the portion of the interstate capacity assets to be retained by AGL to manage and operate the system.

While the i-CDP filings and CSP filings are complementary to each other, they serve different purposes. The Company has stated many times in previous CSP filings that the lead times for capacity resources have increased significantly. The longer-term perspective of the i-CDP helps draw together the near-term nature of the CSP with that of the longer-term perspective needed to secure and maintain adequate resources required to meet the growing needs of Georgia’s firm customers. The 2024-2033 filed and approved i-CDP overlapped with the Company’s 2022-2025 filed and approved CSP, as did the 2019-2022 CSP and the 2022-2031 i-CDP.

**Q.**  **Can you compare and contrast this CSP and the 2024-2033 i-CDP?**

A. This 2025-2028 CSP covers a three-year period between 2025 and 2028 and offers updated load projections for the system’s firm customers; the i-CDP covers a ten-year period 2024-2033. Informed by more recent data, the forecasts for the near term in this 2025-2028 CSP are slightly lower than what was projected in the i-CDP, but the growth trend remains consistent. This 2025-2028 CSP continues to recognize the build-out of the Cherokee LNG facility, which was approved in the Company’s initial i-CDP, and how that gas supply capability will be incorporated into the determination of the Array. This 2025-2028 CSP also includes the modification of the Riverdale LNG facility’s liquefaction process and the establishment of an LNG peak shaving facility, with vaporization capability only, being placed in service in the Valdosta area, both of which were approved in AGL’s 2024-2033 i-CDP.

**Q.** **When you talk about “capacity” in the CSP, what are you referring to?**

A. Capacity is a term used in many ways in the natural gas industry. When capacity is discussed here, it will be in the context of an amount of natural gas that can be delivered to the AGL system by interstate pipelines or from on-system peaking resources. So, for instance, when we refer to “incremental capacity,” we are referring to the amount of additional natural gas delivery capability necessary to meet growth in firm demand, whether through increased deliveries from interstate pipelines or through expanded on-system peaking resources.

**II.** **The 2025-2028 CSP**

**A.** **PRELIMINARY MATTERS AND CSP STANDARDS**

**Q.** **Mr. Becker, please describe your role in developing and administering AGL’s CSPs.**

A. As Director of Capacity Planning, I am charged with securing and administering appropriate firm services on the FERC-regulated interstate pipelines serving the State of Georgia. These pipelines are Southern Natural Gas Pipeline (“SNG”) and Transcontinental Gas Pipe Line Company (“Transco”). Capacity Planning also provides load analytics for AGL. We track and utilize historic weather and firm load information to help develop projections of future natural gas consumption by firm customers on the AGL system.

**Q.** **Has AGL operated in accordance with the 2022-2025 CSP Stipulation the Commission approved in Docket No. 42317?**

A. Yes.

**Q.** **What are the technical requirements for a CSP under O.C.G.A. § 46-4-155(e)(6)?**

A. The Georgia Code imposes four technical requirements on an EDC. Specifically, this statute provides that any CSP approved or adopted by the Commission shall:

(A) Specify the range of the requirements to be supplied by interstate capacity assets;

(B) Describe the array of interstate capacity assets selected by the EDC to meet such requirements;

(C) Describe the criteria of the EDC for entering into contracts under such array of interstate capacity assets from time to time to meet such requirements; provided, however, that a capacity supply plan approved or adopted by the Commission shall not prescribe the individual contracts to be executed by the EDC in order to implement such plan; and

(D) Specify the portion of the interstate capacity assets which must be retained and utilized by the EDC to manage and operate its system. In addition, Commission Rule 515-7-11-.04 specifies the MFRs the Company must file with a proposed CSP.

**Q.** **Has AGL complied with these technical requirements in this filing?**

A. Yes. AGL’s proposed 2025-2028 CSP fully complies with these technical requirements, as my testimony shows. The 2025-2028 CSP includes the Company’s Petition in this docket, my testimony, the MFRs attached to my testimony as AGL Exhibit No. \_\_ (GB-2) (Trade Secret), and the other supporting exhibits to my pre-filed testimony. AGL has provided all of the documentation necessary for support and approval of its 2025-2028 CSP.

**B.** **RANGE OF REQUIREMENTS TO BE SUPPLIED BY INTERSTATE CAPACITY ASSETS**

**Q.** **What range of firm requirements for each year of AGL’s CSP must be met by interstate capacity assets?**

A. The 2025-2028 CSP specifies that the range of firm requirements to be supplied by interstate capacity assets for the three Plan Years is as follows:

* + October 1, 2025-September 30, 2026 (“Plan Year 1”) – 1,861,436 Dth/day;
  + October 1, 2026-September 30, 2027 (“Plan Year 2”) – 1,861,436 Dth/day; and
  + October 1, 2027-September 30, 2028 (“Plan Year 3”) – 2,007,145 Dth/day.

**Q.** **What are the firm Design Day Supply Requirements for AGL’s 2025 - 2028 CSP?**

A. AGL’s 2025-2028 CSP describes firm Design Day load requirement for Plan Year 1 of 2,965,936 Dth, Plan Year 2 of 3,005,936 Dth, and Plan Year 3 of 3,191,645 Dth, including a reserve margin consideration. Reserve margin needs are discussed below.

**Q.** **How were the Design Day Supply Requirements calculated for each Plan Year?**

A. AGL calculated the Supply Requirements forecast for each Plan Year using a multi-variable linear regression model for each of the nine separate pool groups on the AGL system. The Company used this same technique in the last four Commission-approved CSPs. The multi-variable linear regression method continues to be an improvement on the linear spline technique used in earlier CSPs. The multi-variable linear regression approach includes additional descriptive data points to the load models, thereby producing more accurate forecasts. The multi-variable linear regression model determines the nature of the relationship between natural gas demand from our firm customers and weather, as well as other explanatory variables, to predict what the level of firm demand will be at specific Heating Degree Day (“HDD”) levels. When combined, the variables used in the multi-variable linear regression model achieve an improved overall regression fit, better capturing dependent variable response changes given a range of independent variable experiences.

**Q.** **How was this multiple-variable linear regression model applied to determine the range of firm requirements that are reflected in AGL’s 2025 - 2028 CSP?**

A. To determine the range of firm requirements to be supplied by interstate capacity assets as set forth above, we subtracted the maximum planned daily deliverability available from AGL’s LNG plants from the Design Day Supply Requirements.

**Q.** **Are there additional considerations to include as the Company determines that maximum planned daily deliverability from the LNG plants?**

A. Yes. As presented and approved in the Company’s 2022-2031 i-CDP, the Company is expanding the Cherokee LNG facility to increase its storage capacity, its sendout capability, and its liquefaction capability, all to meet the growing firm customer demand of the system. This 2025-2028 CSP recognizes that the Cherokee LNG project includes anticipated added sendout in Year 1 of 160,000 Dth/day, Year 2 of 200,000 Dth/d, and Year 3 of 240,000 Dth/day.

These added sendout capabilities are only viable so long as the plant construction maintains its current project timeline, and the overall expected equipment performance is achieved once placed in service. The minimum required inventory level in the second storage tank is expected to be 800,000 Dth of LNG equivalent plus the necessary tare volumes ahead of the 2025-2026 heating season. However, reaching an inventory greater than this minimum is preferred for a multitude of reasons. Having just 5 days of inventory to send out at maximum sendout rates could become a limitation in a durationally cold winter. If there is an operational issue at another of the LNG facilities, it could mean a heavier reliance on the Cherokee facility. If there are upstream supply disruptions, then on-system LNG resources help bridge the gap. There are more reasons why having a higher inventory volume in Cherokee is preferred, but the limitation of the dated equipment becomes a key driver to what is possible.

For the current LNG refill season (April 2025 through November 30, 2025), the Cherokee LNG facility and its two storage tanks are still relying on the plant’s existing original liquefaction equipment. As described in AGL’s 2022-2031 i-CDP in Docket No. 43820, the existing equipment is dated and remains in service beyond its designed end of life. As a result, the Cherokee LNG plant is currently experiencing decreased efficiencies in the liquefaction process. That means the equipment’s rated ability to create and store LNG is operating less efficiently than expected. Until the new liquefaction equipment installation is completed in late summer of 2025, fully tested, and appropriately calibrated, AGL continues to build inventory in Tank 1 and Tank 2 at Cherokee at the greatest daily rate possible, given the operational limitations of this dated plant equipment.

The next limitation to discuss is the vaporization at Cherokee. As the construction project for the expansion of the facility has been choreographed out, the new vaporization capability, which will allow for a total daily sendout of up to 800,000 Dth/d, can only be installed once the new liquefaction equipment has been installed, calibrated, and tested. The new vaporization equipment will likely not be available until very late in the 2025-2026 heating season—if at all. As such, the planned 560,000 Dth of total daily sendout capability from Cherokee, which is the sum of the 160,000 Dth/d from Tank 2 plus the existing 400,000 Dth/d from Tank 1, utilizes every piece of spare or operational reserve sendout capability available at the plant to its maximum capability. I will revisit this particular risk in our reserve margin discussion later in my testimony.

At this current time, AGL expects to be able to replenish LNG inventories at all 3 of its peak shaving facilities. It is worth noting that similar physical limitations from outdated equipment and systems that do not perform optimally any longer also exist at one other LNG facility—the Riverdale LNG facility. Those limitations stem from the way that AGL’s system is configured today compared to when these LNG peak shaving plants were first put in service several decades ago. The age of equipment coupled with the current operating standards of the AGL system is a limiting factor at Riverdale LNG for liquefaction as well. That is why it was so important for AGL to include a liquefaction modernization element for the Riverdale plant in AGL’s 2024-2033 i-CDP.

**Q.** **Has the Commission approved the use of the multi-variable linear regression model for this purpose in prior dockets?**

A. Yes. As mentioned, AGL has relied upon the multiple-variable linear regression model in its last four approved CSPs. In Docket No. 36792, the Commission issued its Order approving the 2013-2016 CSP on October 28, 2013. In Docket No. 40287, the Commission issued its Order on Reconsideration approving the 2016-2019 CSP on October 13, 2016. In Docket No. 42317, the Commission issued its Order Adopting Parties’ Stipulation for AGL’s 2019-2022 CSP on September 30, 2019. And in Docket No. 44319, on September 29, 2022, the Commission approved AGL’s 2022-2025 CSP.

**Q.** **What factors were included in developing the range of firm requirements other than historic firm customers?**

A. In preparation for the 2025-2028 CSP, AGL made adjustments to the forecasts to account for other factors that are not fully captured by a linear regression analysis, which by definition only identifies the needs of the current customers for which we have sufficient historical data. For instance, AGL includes new firm customers that have been recently added to the system or are reasonably expected to be added in the near future. AGL continues to receive interest from potential new commercial and industrial customers that want firm natural gas service. The Company has historically been successful in adding these types of new firm customers to the AGL system. Because these new and potential firm requirements cannot be represented by relying on a backward-looking linear regression model, AGL included this expected new load when developing its range of requirements for each year of the 2025-2028 CSP. Growth is also seen in the residential customer segment where Atlanta continues to be the largest driver of new billing units. These new customers are captured in the Billing Unit (“BU”) forecast. While customer attrition is also recognized, the attrition rate is much lower than the growth rate, resulting in expected net growth. One of the reasons for the continued net growth in BUs is a growing regional economy. In total, the net BU growth numbers are consistent with the approximate 0.5% overall growth rate seen over the last several years.

**Q.** **Is it appropriate to include incremental capacity for new or existing customers within the CSP?**

A. Yes. The primary objective of the CSP is to ensure that the selected Array will be sufficient to provide safe and reliable service to AGL’s firm customers for the upcoming three-year period. AGL has an obligation to serve all firm load requirements over the next three years without regard to whether those firm requirements existed prior to 2025. AGL cannot simply rely on the static capacity requirements as of 2025 without risking firm requirements exceeding the capability of the selected Array over the next three-year period. Therefore, AGL must include in its forward-looking analysis reasonably expected load additions in its gas supply capabilities or capacity requirements forecast. The Georgia economy, in the Atlanta area and many other cites, continues to enjoy robust growth, and AGL’s forecasts reflect that growth over the next three years.

**Q.** **Has AGL included incremental capacity needs in its analysis in previous Commission-approved CSPs?**

A. Yes. AGL included forecasted incremental capacity needs in its last four CSPs for 2013-2016, 2016-2019, 2019-2022, and 2022-2025, which were all approved by the Commission.

**Q.** **Has AGL included firm demand from data centers or other such large customers in its forecast of firm load requirements?**

A. No. AGL did not include any firm load requirements from data centers or any other such large customers from whom we do not have a commitment or had substantive dialogue about their service needs.

**Q.** **Can AGL meet the needs of a data center if one or more elects to locate on the system and requests firm service?**

A. The Company would certainly welcome the opportunity to serve new customers of that size. Of course, AGL would analyze any customer request for service and provide an appropriate response based on the customer’s selected location, projected levels of firm gas consumption (load), and timing of their development project. But as desirable as adding such large customers may be, AGL cannot commit to serving these larger customers if it means encumbering the system and its stated reserve margin capacity and thereby placing AGL’s existing firm customers’ service at risk. The ability to serve such new firm customers that are not included in the range of firm requirements needs to come from an incremental amount of gas supply capability available to the system that does not degrade the overall surety of gas supply on a Design Day.

1. **BUs**

**Q.** **Is there a difference between a customer and a BU?**

A. Yes. A customer is synonymous with an AGL account, whereas a BU is synonymous with a dwelling or business establishment. A single customer may request or establish service for single or multiple locations. For example, Waffle House is a customer. Each of its multiple store locations represents a BU. Thus, there may be one customer with multiple BUs.

**Q.** **Why do you rely on BUs and not the number of customers to calculate the requirements forecast?**

A. BUs more closely reflect customer usage requirements on a per unit basis than would a simple customer count. Also, BUs are used rather than customers to ensure that when a master meter apartment complex is converted to individual meters, there is no artificial increase in the demand forecast.

**Q.** **How did AGL determine the BUs for this CSP?**

A. The Company used the actual BU count by pool and applied forecasted growth and attrition rates to calculate the forecasted BU for each pool. For each class of customers—residential, commercial, industrial, and multi-family—AGL determined growth and attrition rates using actual BUs for each class for the period from several years of data leading up to the period covered by this 2025-2028 CSP, estimates for the projected effects of customer growth and retention initiatives, anticipated Company initiatives, and anticipated economic conditions.

**Q.** **What overall BU growth rates did AGL use in this CSP?**

A. Similar to the last CSP, the Company anticipates year-over-year growth. This 2025-2028 CSP reflects about a 0.5% increase in BUs per year on average. This varies by pool—in some pools we anticipate a slight decrease, and in other pools meaningful increases are expected. For example, we anticipate the Macon pool to decrease slightly over the 2025-2028 CSP planning period by 0.3% per year, while the Brunswick pool is projected to grow by about 1.2% per year and the Atlanta pool by 0.6% per year. Although there are numerous factors that influence system growth, some of these positive trends outside of the Atlanta area can be attributed to this Commission’s support of efforts to extend service to unserved and underserved portions of Georgia.

**Q.** **Why does the Company develop BU projections at the pool level?**

A. AGL plans for BUs at the pool level because the consumption patterns of firm customers are not the same in each of the nine pools. Additionally, the addition of new firm industrial or commercial firm customers in certain pools can meaningfully move the needle on projected Design Day load levels within that particular pool. The addition of a large customer to the Atlanta pool would likely be obscured by the general size and magnitude of its forecasted Design Day load. However, that same customer electing to take firm service in the Valdosta pool likely would be very noticeable in the change it could trigger.

Pool level details on available gas supply resources are also important. The ability to deliver gas supply to Valdosta is separate and distinct from the Company’s ability to meet firm customer needs in Augusta. Firm customer demand or consumption and the natural gas supply from interstate pipelines must be aligned and provide enough reserve margin to ensure reliable supply to each pool and the system as a whole.

**Q.** **What BUs did you use for the CSP?**

A. The projected BUs are provided in AGL Exhibit No. \_\_ (GB-3) (Trade Secret).

**Q.** **How do these BUs compare to those used in the previous CSPs?**

A. These aggregate BUs continue the previous CSP’s overall growth trend. The 2022-2025 CSP had a BU growth rate of approximately 1.0% in the forecast. This filing reflects a BU growth rate of about 0.5% per annum in total.

**Q.** **Given the Company’s most recent load analytics for the system, what amount of incremental load results from the expected increase in BUs?**

A. Using the regression analytics in this 2025-2028 CSP, the expected increase of 17,400 BUs results in roughly 28,500 Dth of incremental firm load on a Design Day.

**Q.** **Is a 28,500 Dth increase in firm load on a Design Day significant?**

A. Yes. As discussed earlier, unless otherwise planned for, incremental load would significantly erode the reserve margin, which would negatively affect the reliability of the system under extreme operating conditions on a Design Day.

1. **DESIGN DAY DEMAND FORECAST**

**Q.** **What is the purpose of the Design Day or Supply Requirements** **forecast?**

A. The Supply Requirements forecast provides a reasonable estimate of the quantity of gas needed to serve the system’s firm customers on a single day’s usage during certain extreme weather conditions.

**Q.** **Please describe AGL’s methodology for forecasting the total system Supply Requirements.**

A. To determine the Supply Requirements, the Company utilized the multi-variable linear regression model described earlier in this pre-filed direct testimony. The Company then used the resulting regression formula for each pool group to calculate a use-per-billing-unit (“UPBU”) coefficient associated with the respective pool group’s Design Day HDDs. This UPBU is then multiplied by the forecasted BUs for that pool, and the results are summed across the pools. The Company then adds the new load potential from large commercial and industrial customers who have recently come on the system, who have recently converted from interruptible to firm, who have indicated their intent to convert to firm, or are reasonably expected to come onto the system in the near future, as discussed earlier. After adding a reserve margin to the resulting sum, this figure represents the forecasted Supply Requirements. AGL calculated these figures for each pool group for each of the three years in the 2025-2028 CSP. The predominant driver for the forecasted requirements for each year of the 2025-2028 CSP is the projected level of BUs for each pool.

**Q.** **How does the Company’s current approach to the Design Day load projections compare to prior approaches?**

A. The Company’s Design Day load projection continues to rely most significantly on a regression analysis of the relationship between load and weather, as in past CSPs. The addition of non-residential, firm load that has recently come onto the system or is reasonably expected to come onto the system during the duration of the 2025-2028 CSP is also consistent with the way AGL prepared its last four CSPs. As noted, this captures firm load not included in historical data sets, and more specifically, forecasts the unique nature of commercial and industrial BU additions. Because the growth opportunity associated with these future customer additions is not included in the historic data period, this incremental load must be added to the regression analysis’ load calculation.

**Q.** **How does the Company propose to account for the potential load of these new opportunities?**

A. Similar to its last four CSPs, the Company uses a layering method to develop its Design Day load projection. Specifically, the Company begins the layering process by developing a load projection using regression-based analysis on the historical UPBU, historic weather observations, and a BU forecast to determine the existing load on the system and how it is projected to change over the period of the 2025-2028 CSP. This portion of the forecast captures most of the load expected on the system in a Design Day event. Next, the Company factors in a layer of load potential for new opportunities from new large firm customers expected to join the system that cannot be captured in the regression analysis.

**Q.** **What is the relative size of the Design Day load contributions from BU driven load versus the added load from new firm customers?**

A. The BU driven load, which is the result of regression analysis of historical consumption information, is 98% to 99% of the overall Design Day forecast. The remaining 1% to 2% is from the identified new firm load opportunities.

**Q.** **Do you believe it is appropriate to calculate Design Day load in this manner?**

A. Yes. This is the same process used in AGL’s last four CSPs. Put simply, unless this process is used, the Company may not have sufficient capacity to serve firm load as new customers look to come onto the system. Without sufficient gas supply resources or capacity, AGL would have to reject these potential customers, who may then locate their businesses and associated jobs in other metropolitan areas or in another state. AGL has managed to proactively position itself to be able to say “yes” when these customers seek firm service rather than having to turn them away. That must continue.

**Q.** **How far out in time do these incremental load projections go?**

A. Based on active leads in the sales pipeline for AGL’s New Business Development team, AGL has identified load which is typically looking for service in the next 18 to 24 months. Because there is a high likelihood that additional incremental firm sales opportunities will continue to present themselves beyond this short time horizon, a simple projection based on historical average growth and attrition was developed by our Growth, Retention and Customer Analytics group to fill in the gaps in a longer-term forecast.

**Q.** **How does the Company account for the lack of more detailed information in the later CSP months?**

A. The Company recognizes the potential for more load additions beyond what is forecasted in the 2025-2028 CSP—particularly in the final year or two of the 2025-2028 CSP. AGL continually monitors economic development in its service area. The Company will determine whether modifications to the 2025-2028 CSP’s Supply Requirements are necessary and whether a corresponding CSP amendment is appropriate based on changes in load expectations during this Plan period.

**Q.** **In your opinion, is the total Design Day load forecast included in this filing reasonable and necessary to reliably and safely serve firm customers and allow for system growth?**

A. Absolutely. The total Design Day load projected in this case is both reasonable and necessary for continued safe and reliable operations of the AGL system.

1. **ANNUAL FIRM THROUGHPUT FORECAST**

**Q.** **Please describe the forecast of the annual firm throughput volumes?**

A. AGL calculated the annual firm throughput forecast for each pool group using a baseload and a heat sensitive factor per BU assuming a weather pattern based on the 10-year average. In addition, similar to the Design Day load forecast, AGL added new large commercial and industrial load using these customers’ projected peak usage. The Company then summed this forecasted annual firm throughput for each pool group to calculate the total system annual throughput. For capacity planning and contract level decisions, the Company also evaluates potential firm load and throughput requirements assuming a 30-year average weather pattern.

**Q.** **Please describe the modeling technique used to determine the base load and the heat sensitive factor per BU.**

A. For every month for each of the nine pools, AGL performed a regression analysis using historical data for the months April 2020 through March 2025 to determine a UPBU. The regression input included information, such as the prior day’s temperature, the day of the week, holidays, wind speed, and other explanatory variables. These regression analyses were performed using Business Forecast Systems Inc.’s Forecast Pro 100 v12, as in prior CSP filings.

**Q.** **Is this the same methodology and modeling technique used in prior CSPs accepted by the Commission?**

A. Yes.

**D.** **RESERVE MARGIN**

**Q.** **Can you describe the Company’s general position on reserve margin increases included in this CSP?**

A. Yes. AGL believes that establishing a more reasonable overall system level reserve margin in this 2025-2028 CSP is essential for the continued safe and effective operation of the system and is central to providing natural gas service to our customers when they expect it to be available without fail.

**Q.** **What is reserve margin?**

A. Reserve margin, in the context of an EDC’s obligation to provide safe and reliable gas service to its firm customers, is an amount of capacity or gas supply capability that is in addition to the forecasted firm load on the system. It is usually stated as a percentage of the projected firm load on a Design Day.

**Q.** **What is the purpose of reserve margin?**

A. Reserve margin affords the delivery of an extra amount of natural gas to the distribution system to minimize disruptions to satisfying firm load requirements. It is meant to ensure that there are sufficient resources to meet firm load on a Design Day in the event of a supply disruption(s) and/or in the event actual firm load is higher than forecasted Design Day.

**Q.** **Please describe these potential events in more detail.**

A. Reserve margin, at a high level, is established to provide uninterrupted gas supply capability while absorbing uncertain events that can occur in extreme weather events. There are four general categories of uncertainty. The first is the load forecast itself. The second is the HDD standard being used for the projection of the Design Day load. The third element is the uncertainty of mechanical equipment operating as required in extremely cold environments. And finally, the fourth element is customer behavior. For simplicity's sake, I will discuss these four elements in the context of the system’s Atlanta pool. However, each of these elements exists in each of the nine geographic pools across the AGL system.

The total gas supply requirement in a CSP is a projection of possible firm load at a 55 HDD weather event (for the Atlanta Pool). By its very nature, any forecast has an error in it. AGL has done all it can to reasonably identify, quantify, and mitigate the forecast error in setting its Design Day forecast. However, an average temperature of 10℉ for a day (55 HDD day) does not happen often. Therefore, any projection of expected firm demand or natural gas consumption is an estimation, not a definitive value. The Design Day forecast of firm demand is an approximation based on tested and validated analytics.

The planning standard for an HDD value used in the load forecasts for each of the nine pools also introduces an irrefutable risk. AGL tracks the historical weather that has been encountered over decades in the State of Georgia, and it is a fact that the State has encountered weather in the past that is colder than the planning standard for its Design Day forecasts. In fact, the coldest recorded day was a 65.6 HDD day—a full 10 degrees colder. Knowing that it has in fact been colder than the planning standard of 55 HDDs is a quantifiable risk.

There is a further risk to the 55 HDD planning standard. It is not just that it has in fact been colder than is being planned for. The most troubling concern is that weather records are broken all the time. We see it regularly on the evening news. During the week of June 23, 2025, as the Company finalized its testimony, there were records set across the eastern half of the country for record hot weather. When will it be Georgia’s turn to experience a new record cold weather event? Statistically speaking, the State of Georgia may be due. In 1985, the record low temperature on January 21st was -8 degrees. The day before, January 20th realized a low temperature of -6 degrees. Bone chilling cold weather was experienced on consecutive days and each of them was meaningfully colder than the 10-degree average daily temperature that is currently planned for. Such extreme weather conditions can bring health, human safety, and property damage risks, even after a short period of time.

It is a fact that mechanical equipment operating during extreme cold temperatures introduces a unique operational risk of failure. The process of delivering natural gas to more than 1.7 million firm customers relies heavily on mechanical equipment—electric motors that drive pumps, remote controlled valves and actuators, and even old diesel-powered liquid pumps that are temperamental to start even in normal weather. Any number of these pieces of equipment could fail to perform in the extreme cold weather conditions described above or that yet unseen even colder weather event. Failures of equipment during those extreme conditions also require employees to respond to the issue and rectify it. Performing repairs in such weather conditions also comes with inherent risks to mitigate and overcome.

Another variable that is exceedingly difficult to predict is customer behavior. The Company plans for a 10-degree average temperature day today. Customers watch weather forecasts. When they see a day that cold, or colder, heading their way on the 6 o’clock news, they are going to respond. They will bump the temperature a bit higher on their thermostats. They will flip on those gas logs to chase away the chill. They will enjoy a longer warm shower. They will pre-warm their clothes or jackets before braving the cold outdoors. Generally speaking, their usual consumption patterns probably won’t hold true in extreme circumstances. It is very difficult to plan for that unknown factor of human behavior in a possible scarcity situation. Look at the egg shortage at the end of 2024. People were stocking up on more eggs than they would typically use in a whole month-long period—just to ensure that they got all they wanted.

**Q.** **Has AGL’s reserve margin been used in a manner that is consistent with the explanation provided above?**

A. No. AGL has held an approximate 5% system wide level of reserve margin capability throughout the last six CSPs. In that time, the system has not encountered weather conditions that would classify as a Design Day. However, each heating season does have a peak sendout day or a highest demand day. Some of these peak day sendout volumes have approached projected Design Day levels of firm natural gas requirements, even at temperatures warmer than a Design Day HDD. Reserve margin historically has been used to accommodate routine system load growth. The net effect is to have a level of additive gas supply capability that is less than, in some cases meaningfully so, the stated planned levels.

One easy recent example illustrates the point. In January 2025, AGL successfully converted an existing interruptible customer over to being a firm customer. The conversion was effective January 1, 2025. The new firm load amount was around 8,400 Dth/d. That added firm load obligation to serve was not offset by AGL going to the market and seeking any additive gas supply capability. It was covered by the system’s available reserve margin. It is very fortunate that AGL was in a position to accommodate this new firm load while meeting the overall needs of the system.

A similar set of circumstances played out in the Valdosta area over the past couple of heating seasons. First, a larger interruptible customer elected to convert to firm service. Next, AGL was informed that an existing firm customer intended to double their manufacturing capabilities and consume twice the amount of natural gas the customer historically had consumed. The third firm load increase came in the form of a press release announcing a new firm customer connected to economic development load in the area. All of these positive outcomes were covered, from a firm gas supply perspective, by utilizing all of AGL’s reserve margin gas supply capability in that part of the system. The Company is now moving forward with the addition of a scalable, vaporization-only LNG peak shaving facility in that part of the system to restore reserve margin capability along with other new firm transportation capacity options.

AGL has successfully migrated numerous interruptible customers to firm service over the last three years. Such conversions across all three years of the last CSP totaled 27,401 Dth/d of new firm load. That volume represents 20% of the minimal 5% system wide reserve margin; 137,003 Dth for Year 3 of the 2022-2025 Plan. All of that firm gas supply requirement came out of system reserve margin capabilities. That, most definitely, is not what reserve margin is for.

**Q.** **Are there other examples where real time customer changes have impacted the system’s available reserve margin?**

A. Yes. The new incremental load added during the 2022-2025 CSP period from interruptible to firm service conversions alone is equivalent to about 20% of the available reserve margin for the entire system on a Design Day. That, coupled with the new firm customers that were actually added to the system, accounts for nearly 132,000 Dth/d of added firm demand. The reserve margin set in the 2022-2025 CSP for the **entire system** was only about 137,000 Dth for Year 3 of that Plan. Had AGL not incorporated a projected level of new customer growth in its forecasted Design Day requirements, the system would not have been able to realize the positive growth that it did. This simple example shines a light on the inadequacy and the significant risks of past practice when it comes to the level of reserve margin and how it is being used.

Reserve margin is meant to cover the “unknowns” of operating a physical system of mechanical equipment and satisfying the consumption patterns of each and every one of our firm customers—the newest of the new and the longest connected customer on our system, which changes at any time, all while being responsive to whatever weather conditions may come.

**Q.** **What reserve margin did AGL include in the planning criteria for this filing?**

A. AGL included an increased reserve margin of 7.1% in Year 1, increasing to 9.2% for Year 3 of this 2025-2028 CSP. The longer-term perspective on this level of reserve is discussed later in my testimony. Due to the lumpy nature of capacity contracting on interstate pipelines, Year 1 of the next filed Plan, based on current information, will be at a higher level than any one year in this 2025-2028 CSP. The added firm transportation capacity that AGL has signed up for will be available in late 2027 for the winter of 2027-2028. The bulk of the new capacity is expected to be available in the following winter of 2028-2029. The capacity comes in blocks of incremental capability. That is what I mean when I say “lumpy nature.”

**Q.** **Can you put that percentage level in context for this CSP period?**

A. Yes. A 7% reserve margin is about 198,000 Dth/d of firm gas supply capability. For comparison, that is about 41% greater than the sendout capability of the Macon LNG facility. That comparison is important. Macon LNG has just two sendout pumps to make its 140,000 Dth/d of sendout available to the system. The other LNG facilities, Cherokee and Riverdale, have adopted an N+1 redundancy to recover in an outage situation. That simply means that these two plants each have a spare set of equipment to cover the loss of a vaporizer. If one of those pumps at Macon were to fail, that would result in an immediate loss of 70,000 Dth/d of gas supply capability.

If the minimal 5% reserve margin standard were to remain in place, the total system reserve margin level would be about 140,000 Dth/d of capability. Should an operational issue at Macon happen, then up to 50% of the entire system’s reserve capability would be committed to covering that single event failure. That leaves nearly 1.8 million BUs subject to the risk that actual weather is colder than 55 HDDs. As stated earlier, colder weather events have happened numerous times in Georgia’s history. Georgia does not want to be on the evening national news for customers being without service for days at a time during an unprecedented winter storm, as was the case for winter storm Uri and the folks in Central Texas. Forecasted consumption for those 1.8 million firm BUs cannot be underpredicted or that 70,000 Dth/d of capability will be quickly depleted.

**Q.** **Can you discuss the operating risk at Cherokee LNG that you mentioned earlier in your testimony?**

A. Yes. AGL’s planned sendout level from the Cherokee LNG facility for Year 1 of this 2025-2028 CSP is a total of 560,000 Dth/d. That is 400,000 Dth/d from tank 1 capabilities and another 160,000 Dth/d from the stored inventory in tank 2. I also described how Riverdale and Cherokee LNG both utilize an N+1 fail over in their equipment design standards. Until the new vaporizer equipment is installed at Cherokee, the sendout from that plant is utilizing all the installed physical vaporization equipment available at the plant. There will not be a redundant capability to rely upon if any portion of the LNG vaporization related equipment fails. That means there is an elevated operational risk in planning for up to 560,000 Dth/d of LNG sendout from that plant. That risk is mitigated when the new vaporization capability is in place. That new equipment will be constructed and put into service after the new liquefaction equipment is put in place late in the summer of 2025. All of this mapped out construction activity is expected to be wrapped up in time for Year 2’s heating season. Until then, a reserve margin greater than 5% is justified simply due to the added sendout risk that will exist at Cherokee LNG.

**Q.** **Is reserve margin equal in all pools?**

A. No. Each pool has its own relative reserve margin based on how natural gas is delivered to the pool from interstate pipelines or if the pool can be served by on-system peaking resources. Accordingly, the resources from one pool may not necessarily be available to meet another pool’s needs. The Company’s analysis does evaluate the amount of reserve margin in each pool relative to its representative load.

**Q.** **Are there any recent historical weather and load events that are significant relative to a discussion of reserve margin?**

A. Yes. Just a few quick facts and figures before discussing a specific example. Ten of the top 25 all-time highest sendout days have occurred in the last three gas years. Five of those ten events were in 2024-2025’s heating season. Four of the top five all-time sendout days were encountered in the last three heating seasons. The all-time sendout event occurred on December 23, 2025. That was a Friday leading into a holiday weekend, and the sendout was recorded as 2,334,778 Dth on a 51 HDD day.

That is significant when compared to the second highest sendout day on January 21, 2025, a Tuesday recording 2,197,074 Dth on a 43 HDD day. A 2.2 Mdth of sendout compared to a 2.9 Mdth forecasted Design Day at a temperature that is only about 12 degrees colder. Comparing these two historical loads, 2.3 Mdth at 51 HDDs and 2.2 Mdth, a full 8 HDDs warmer, are two data points that seem to indicate that when the weather turns cold, the load will show up. One last observation on these historical events is important to note. The peak sendout event in 2024-2025 occurred over a 3-day period starting January 21 and the colder weather subsided on January 23. January 22 and January 23 were at 36 and 33 HDDs. Even these mild January days rank in the top 25 sendout days for the AGL system.

**Q.** **What is the most extreme weather day you are familiar with and what level of reserve margin would be needed to meet that demand?**

A. On January 20, 1985, the Atlanta area encountered a 65 HDD day—a full 10 degrees **colder** than the current Design Day planning criteria. Eight of the nine geographic pools experienced their coldest day on record. Should such an event be repeated, the resources planned for this filing would be insufficient to meet demand. Specifically, to meet demand on such a day, the proposed 2025-2028 CSP would require an additional 229,128 Dth/d of firm delivery capability. This is 30,847 Dth/d above the capacity and increased reserve margin level of the Array of Plan Year 1, and it would result in a need to curtail the equivalent of the consumption of around 20,000 Atlanta area residential customers on a Design Day.

**Q.** **What level of reserve margin would be necessary to support that type of event?**

A. Using current consumption information and BU forecast, AGL would need a reserve margin of 8.3%, with gas supply capabilities in the right places across the nine pools, to meet demand and support a repeat of this type of weather event.

**Q. Are there alternatives to holding a higher reserve margin?**

A. Yes. AGL could modify its planning criteria to forecast its Design Day load based at 65 HDDs, the coldest HDD level experienced in history. Setting the firm demand requirements to be driven off the coldest weather event in history for the State of Georgia removes significant risk from the process. Planning for just a 55 HDD Design Day is an inherent risk; one that the system has adopted and operated under for years now that has not resulted in negative consequences.

**Q. Is the Company recommending such a change?**

A. No, that is not the Company’s recommendation in this filing.

**E.** **CAPACITY ENHANCEMENTS**

**Q.**  **What criteria does AGL use to consider and evaluate potential new capacity contracts?**

A. The CSP planning process is focused on ensuring reliable, cost-effective natural gas on behalf of end-use customers in Georgia. AGL’s primary objective as potential new contracts are evaluated is to supplement or modify the existing Array so that the needs of firm customers can be met on a Design Day during any winter during the Plan period. Mitigating risks associated with serving Georgians on the coldest days of winter, when customers rely most heavily on natural gas, is the primary consideration.

Consequently, AGL considers the extent to which any new service provides a good fit with the existing services within the Array to meet the need for incremental capacity, based on the system’s changing needs. For example, if the system’s greatest needs are for new peaking services, then a new peaking service would be preferred over year-round transportation services. AGL works to achieve this fit, even when the services offered do not match as well as one may have hoped.

In addition to matching the needed load profile of the system, it is critical that new services match the geographical needs of our customers. Indeed, it is important that gas can be delivered to the areas of Georgia that need it, and that the new service can access natural gas production areas that are both reliable and cost-effective. Thus, pipeline proximity and interconnectivity are important considerations.

Operational characteristics are also important. In addition to being reliable, AGL considers any new opportunity’s operational flexibility such as nominations, secondary market opportunities, and ability to augment the value and operation of existing assets within the Array. These considerations add potential value to end-users on AGL’s system as well as market participants.

Cost is always a factor that is considered. While the goal is not necessarily to get the least-cost available option, getting the best value is a core objective. Ultimately, a higher cost option may be a better value, considering the factors enumerated above such as reliability, fit, flexibility, and ability to augment existing assets within the Array.

**Q.** **Are there additional criteria or considerations?**

A. Yes. While my answer to the previous question would be the optimal way to assess and evaluate two competing alternatives, as a practical matter, in today’s capacity constrained interstate pipeline markets, gas distribution companies like AGL often do not have the opportunity to choose between competing alternatives. Sometimes, there may be only one option to meet customers’ needs. In such cases, the task then becomes either trying to include terms of service within the single offering that better match the criteria above or creatively using the new asset. The arrangement with a Georgia Energy Provider (discussed below) is an excellent example of a creative use.

**Q.**  **Is it possible to maintain capacity rights that exactly match AGL’s calculated firm demand, plus a reserve margin?**

A. No. Capacity additions are acquired in chunks of capability at a time, whether it is added firm transportation on an interstate pipeline or the development of a new peak shaving LNG facility. At any given moment in time, AGL’s actual capacity or ability to deliver gas supply to the system will vary somewhat from its forecasted firm demand requirement. It is unavoidable.

**Q.**  **Is AGL introducing new contracts into the Array by participating in any pipeline expansion projects on the interstate pipelines that deliver to its system?**

A. Yes. After considering the criteria discussed in response to your previous question, AGL is participating in pipeline expansion projects on both interstate pipelines that serve the State of Geogia. The Transcontinental Gas Pipeline (“Transco”) project, called the Southeast Supply Enhancement (“SSE”) project will provide a diverse source of supply to the AGL system with a firm transportation path originating at Transco Station 165 and delivering to AGL’s system between Station 130 and Station 115. Station 115 is at the southern end of the Dalton Lateral, which extends northward along the western side of the Metro Atlanta area. AGL has subscribed to 75,000 Dth/d of firm transportation capacity in the SSE project.

Southern Natural Gas (“SNG”) is also sponsoring an expansion project called South System Expansion 4 (“SSE4”). It too will provide incremental firm transportation capacity for AGL’s system. AGL has subscribed to 200,000 Dth/d of firm transportation capacity in this project. The capacity will provide delivery capability of 145,000 Dth/d to the metro Atlanta area, 50,000 Dth/d to the Augusta area, and 5,000 Dth/d to the Valdosta area. Receipt capacity for this project will be in SNG’s production area back at Rose Hill.

These two blocks of new interstate pipeline capacity, coupled with bundled peaking and a growing sendout capability from Cherokee LNG, all allow AGL to grow the system’s level of gas supply capability and by extension, its reserve margin, going forward.

**Q. Is AGL participating in any other pipeline expansion projects?**

A. Yes. AGL is also participating in an upstream pipeline development project called Mississippi Crossing (“MSX”). This project is sponsored by Tennessee Gas Pipeline, an interstate pipeline owned by Kinder Mogan. Kinder Morgan also owns the SNG pipeline. This project is considered an upstream pipeline for AGL since it does not deliver gas to the AGL system. Rather, it connects the SNG and Transco pipelines to new and more robust gas supply regions to access diverse sources of flowing gas supply. The project allows for up to 206,000 Dth/d to be delivered into SNG or Transco at points where MSX will interconnect with the two delivering pipelines to get gas to the AGL system.

AGL teamed up with another Georgia energy provider (the “Unnamed Provider”) on the MSX project. AGL will share a portion of this expansion project’s capacity, which reduces the costs borne by AGL’s firm customers. AGL will have access to the full volume of 206,000 Dth/day October through April of each year, once the project goes into service. However, in the months of May through September, the Unnamed Provider has contracted for a large portion of the 206,000 Dth/d in their own name. That means in the months of May through September of each year AGL contracted capacity will equal 87,000 Dth/d. Since AGL’s load is heavily correlated to space heat needs and HDDs, having this alternate shipper able to contract for that capacity when the AGL system is less likely to need it is a very favorable economic advantage for our customers. This is another example where AGL has found a creative use of energy capabilities that meets the needs of the State of Georgia.

**Q. When will these projects be placed into service?**

A. Transco’s SSE project is expected to be in service in late 2027, in time for the 2027-2028 heating season. SNG’s SSE4 project is expected to be fully in service in late 2028, in time for the 2028-2029 heating season. However, in the case of SSE4, it is likely that a portion of the project, 50,000 Dth/d, will be placed into service early and be available for the 2027-2028 heating season. Therefore, this 2025-2028 CSP filing includes 50,000 Dth/d of the total SSE4 capacity being available for the 2027-2028 heating season with the balance of AGL’s SSE4 project capacity being available the following year. This is reflected in AGL’s outlook for the subsequent planning period. It is important to note that as we look at the years immediately beyond the period of this 2025-2028 CSP, the available capacity to the system will increase, and reserve margin levels will rise accordingly. That is one of the effects of capacity coming in blocks at discrete periods of time.

**D.** **DISCUSSION OF CHANGES**

**Q.**  **Are there changes proposed in this CSP that you can explain?**

A. Yes. AGL has three primary changes to describe in this 2025-2028 CSP filing. The first, as described above, is the introduction of new, incremental firm transportation capacity on the two interstate pipelines that provide service to Georgia, as well as new firm upstream transportation capacity. The second change is a proposed swap of resources between services held in Firm and Interruptible Nominated Sales Service (“FINSS”) in exchange for services that are currently released to Marketers. The final change is the removal of the Dalton firm transportation split of Marketer Accessible Retained Storage (“MARS”) service that was introduced several Plans ago. Central to this entire 2025-2028 CSP is a revision to the reserve margin as discussed above. There are further minor changes discussed as this section of testimony concludes.

**Q.** **Are there any other details to share regarding the new firm transportation capacity?**

**A.** Yes. The Company has described in several of its past CSP and i-CDP filings that interstate pipeline expansion projects are not common. Occasionally, a pipeline may create an expansion project for a single shipper’s needs. Most often, they come together when the pipelines can assemble enough interested shippers to justify the expense and time it takes to move an expansion project from concept to completion. SNG and Transco each approached AGL and several other shippers about concepts of expansion projects back in 2023. By late 2024, AGL had entered into binding agreements with each pipeline for incremental firm transportation service. The entire process of placing this new capacity in service will take no less than four years if everything continues to go smoothly from this point forward. AGL needed to make a commitment to these projects well in advance to have the appropriate amount of gas supply capability for the system in the years it is expected to be needed. As there is such a significant lead time associated with a pipeline expansion project, plans for such capacity must be made far in advance. Waiting until 2026 to express a need in 2027, for example, is simply not a viable option. If AGL were to rely on short term identification of new pipeline capacity requirements, it would continuously miss the window to support economic growth and development in the State of Georgia.

**Q.**  **Can you please explain the proposed swap of resources?**

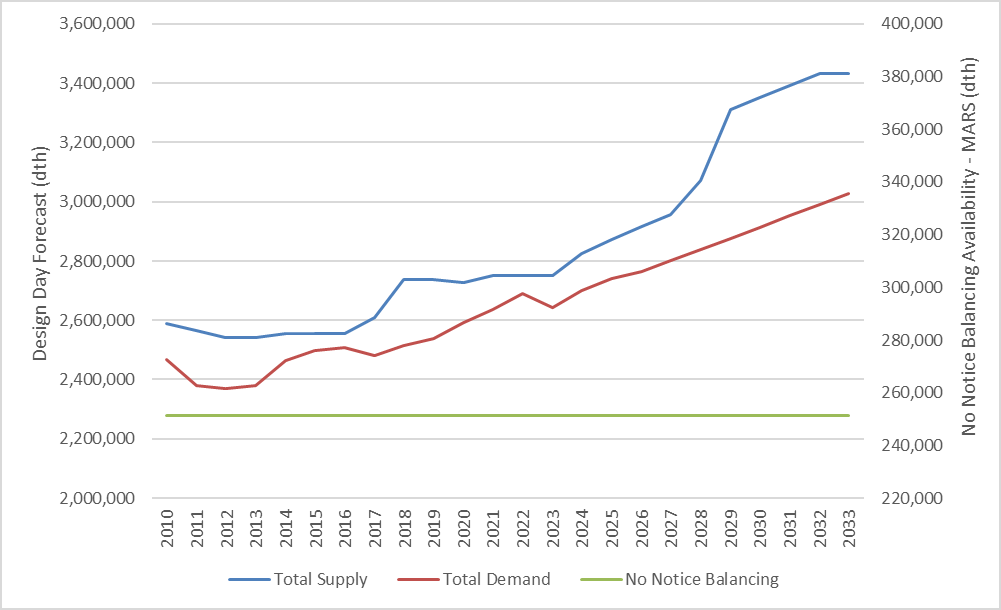
**A.** AGL has proposed two resource swaps between the Company and the Marketer community.

The first swap involves MARS. AGL suggested an exchange of SNG storage capability and related no**-**notice firm transportation capacity for National Fuel Gas (“NFG”) storage service, related NFG firm transportation capacity, and two different Transco firm transportation capacity contracts, all of which are required to withdraw gas from the NFG storage service and deliver it to the AGL system. NFG FSS is provided by an interstate pipeline company located in the Northeastern US, specifically in Western New York and Northwestern Pennsylvania. Today NFG FSS is a component of the FINSS service. The CSS and related SNG FTNN no-notice transport are currently released to the Marketers. CSS service and its transport provide no-notice balancing service to the AGL system across seven of the nine pool groups on the system. AGL’s no-notice balancing services are held in the MARS service. This swap will decrease FINSS and increase MARS by a like amount. You can see this change in Exhibit (GB-4) (Trade Secret), Resource Summary comparing Year 2 to Year 3. This change does not impact or decrease AGL’s overall ability to deliver natural gas to its system for firm customer demand.

For nearly 20 years, MARS has remained at the same level of service. This proposed swap of resources will slightly increase AGL’s no-notice balancing capability and will aid AGL as it balances the physical consumption of gas by our firm customers with the aggregate amount of natural gas being delivered to the system on a daily basis. AGL’s load has grown meaningfully over the years, so having slightly more MARS balancing capability is a much-needed operational benefit.

**Q.**  **Can you explain why this slight increase in no-notice balancing capability in MARS is needed now?**

**A.** Yes. The graphic shared below lays out how AGL’s total Design Day load has grown and will continue to grow in the period of 2010 through 2033. It also shows how the aggregate MARS capability has remained unchanged over time. Additionally, the overall amount of firm gas supply capability for the system has grown commensurate with the increases in expected firm load. This minor upward adjustment to the system’s overall no-notice balancing capability is operationally necessary now more than ever.



**Q.**  **Please explain the second resource swap.**

**A.** The second resource swap involves LNG. AGL proposed a swap of inventory space equivalents—between Leaf River storage for on-system LNG. The general concept is over a 4-year period, beginning April 1, 2027, AGL would release incremental amounts of Leaf River storage service to the Marketers, and the Company would take back a like amount of inventory space in the on-system LNG facilities in which the Marketers currently hold inventory. Leaf River storage is a component of the system’s FINSS. At the end of 4 years, AGL will have transitioned to operating the LNG facilities and being responsible for their dispatch to support system operations as well as their refill following a heating season or usage from the inventory. Likewise, the Marketer community would receive a like amount of inventory capability and the associated daily injection and daily withdrawal capability of the Leaf River service. An appropriate matching amount of SNG firm transportation would also be released so Marketers could deliver withdrawals from Leaf River to the AGL system.

There remains several aspects of this swap arrangement that need to be effectively planned for before the start of the transition. AGL looks forward to collaborating with Marketers and Staff to ensure an efficient exchange. If all of these matters, and any others that are discovered through further examination, cannot be fully addressed, at the Company’s sole discretion, then this aspect of the 2025-2028 CSP will be withdrawn before the start of the transition in April 2027. The provisions of the 2022-2025 CSP will remain in effect if this swap opportunity is eliminated in this CSP.

**Q.**  **What types of transition matters does the Company foresee?**

There will likely be tariff modifications necessary to provide for this change. A Peaking Sales Service, similar in nature to FINSS or Bundled Pipeline Peaking Service (“BPPSS”), would need to be established. AGL would simply sell LNG peaking supplies to Marketers based on system firm load conditions and operations. While not an exhaustive list, these further operational and logistical matters will be central to the development of the Tariff provisions and discussions:

* LNG Service will become the last resource dispatched in the resource stack
* Discretionary (economic) LNG access will be held at the levels in the 2022-2025 CSP, be ramped down through the transition period and ultimately removed
* AGL, at its sole discretion, will determine if heating season liquefaction or trucking is necessary to maintain or re-balance the available LNG inventory to maintain system reliability and/or integrity of the service
* Sales service rates will allow for full recovery of all current or future costs incurred by AGL to provide the commodity portion of service to Marketers for our Firm customers
* Carrying cost on inventory will be a component of cost recovery used to calculate the effective sales price (consistent with the manner calculated for MARS)
* Firm transportation capacity will be retained at levels to appropriately support summer refill periods as well as potential winter liquefaction needs
* With the exception of the NFG for CSS exchange, no other changes to the planned Array or the asset stack will be made until we gain operational experience with this new LNG service
* The exchange will need to maintain a revenue neutral impact on the asset management value and its resultant contributions to the USF
* Costs for any IT system upgrades and improvements necessary to effectuate this change will be the responsibility of the Marketer community

**Q.**  **Describe the timeline for this transition?**

The swap will take place at the end of each heating season, effective April 1, for 4 consecutive years. LNG inventory would be at its lowest. Leaf River’s inventory would also likely be at its lowest. The Company would release empty Leaf River inventory space and take back empty LNG inventory space. That allows the swap to happen and not involve gas costs or either party having to pay the other for gas in inventory. The goal is to make this swap in a way that does not impact the customers. Exchanging space for space is the preferred way to proceed.

**Q.**  **What other types of transition matters might present themselves?**

A, If there comes a circumstance where LNG inventory is at a low level, following a durational cold winter for example, the Company and Marketers can discuss the option of accelerating the space for space swap. Neither party will be obligated to move forward with an accelerated transition. All Marketers need to agree to the acceleration or the year-by-year transition continues.

If at the final stage of the transition period, there is an amount of inventory remaining in either Leaf River or the LNG facilities, the Company and the Marketers shall agree on a way to settle the impacts that works to mitigate any impact on our firm customers.

**Q.** **Will AGL continue the seasonal summer-only firm transportation release with Oglethorpe Power Company (“OPC”) that was noted in the previous CSP?**

A. No. The summer-only capacity that AGL had been releasing to OPC is no longer necessary. OPC and AGL approach SNG to split the contracted capacity seasonally. Now AGL’s firm transportation capacity contract is a seasonal firm transportation agreement. In the months of October through April, the 87,000 Dth/d of firm transportation capacity is available for the AGL system. In the months of May through September, the contract for that same 87,000 Dth/d of firm transportation capacity is in a service agreement between SNG and OPC. AGL is no longer responsible for that capacity or its reservation costs. The capacity is now permanently assigned to OPC. This was a meaningful co-operative step for AGL and OPC that minimizes fixed cost exposure for our firm customers while also providing a better overall energy solution for the State of Georgia. When and where appropriate, AGL will continue to look for other cost-saving opportunities that benefit our customers, the State, and the energy needs of the region.

**Q.** **Are there any other operational changes or matters that will come up during this 2025-2028 CSP period?**

A. Yes. The Company has three other matters that will be relevant to system operations that are important to lay out in the next three years. First, the Company will formalize how operations around the SNG North Main delivery points will be handled. Second, with all the improvements being finalized at Cherokee, Riverdale, and the installation of the new sendout only LNG peaking facility in Valdosta, there will need to be a discussion around how those physical facility changes will impact system operations. Finally, the Company will finalize details around an appropriate daily balance of Transco versus SNG gas that the system can take.

I have discussed multiple aspects of the Cherokee facility’s ongoing upgrades and expansion. Once the new liquefaction equipment, new vaporization capability, and the added storage tank are 100% complete, tested, and calibrated, it makes sense to revisit the long-standing operating assumptions around that facility and how it will be fully integrated into the gas supply aspects of LNG operations. AGL is not envisioning meaningful changes, but it is appropriate to take a fresh look at everything once the expansion project is finally wrapped up.

The SNG North Main matter has been discussed with Staff and the Marketer community countless times. The Company plans to migrate toward a market share driven delivery obligation as soon as the EGMS system can be modified to manage the transition. Since that platform deployed on June 1, 2025, it is too early to pin down an exact date on when appropriate modifications could become available. However, the Company will work with Staff and Marketers to move toward completing the work as soon as it is feasible in that platform’s development cycle.

Finally, the daily ability to deliver both SNG and Transco volumes to the AGL system is an operational benefit. However, these discrete supply sources are not fully interchangeable. The system needs a certain amount of physical delivery off each of these interstate pipelines to effectively operate the system. AGL will continue to develop its analysis and understanding of the physical needs of the system. With that, conversations with Staff and Marketers will be held so that these operational needs can be formalized either by operational measures or tariff modifications, possibly both, in the coming months. This will likely involve EGMS modifications. The same commitment to map that out and integrate it into the platform’s upgrade cycle as described above will apply here too.

**Q.** **Are the Dalton MARS topic and the use of Elba capacity carryover items from the 2022-2025 Plan?**

A. Yes. The removal of the Dalton firm transportation that had been bisecting the MARS service is being eliminated with this filing. That is consistent with the Company’s settlement position on this matter in the Commission-approved 2022-2025 CSP. The level of on-system LNG peaking utilization that would require Marketers to deliver gas on the firm transportation with receipt entitlements at Elba Island was also a consideration in the last Plan. Year 3 of the last Plan set the aggregate use of on-system LNG Peaking at 500,000 Dth with an ability for AGL to require the firm transport to be utilized up to ten (10) days in a heating season. For the 2025-2028 CSP, AGL’s filing includes setting the aggregate LNG peaking use level at 550,000 Dth of needed sendout. That will be coupled with ten (10) days of utilization of what has been called the Magnolia Capacity. The main driver for this change is the need to complete the liquefaction and vaporization installation work at Cherokee and the transition of the liquefaction equipment that is planned at Riverdale, along with recognizing the increase in LNG sendout capability that is expected to be available as that work is completed.

**Q.** **Will the Company consider ending this Magnolia Capacity contract?**

A. No. This capacity provides 83,722 Dth/d of delivery capability to the AGL system. Its unique transportation path, with receipt rights at Elba Island and delivery entitlements in Brunswick and Macon, having Savannah in the path is needed for supply resiliency. Its unique contract path, and the way that it has been incorporated into the operation of SNG’s pipeline system, avoided the potential loss of service to AGL’s customers in South Georgia in the closing days of April 2025. An inadvertent line strike ruptured a line in South Georgia. The damaged segment of line was quickly isolated and valved closed at both ends, and the leak was stopped very quickly. Since SNG can physically push gas to AGL’s system flowing North to South toward Brunswick as well as South to North toward Macon along our diverse contract paths, SNG was able to repair the damage without disruption in service to any of our customers. Prior to having this Magnolia Capacity, the bi-directional flow capability did not exist. A pipeline damage like that would have likely led to customer outages in the Brunswick area.

**Q.** **Does this filing include provisions to terminate any gas supply capabilities that were in prior filed and approved Plans?**

A. Yes. This Plan includes an agreement to allow a package of firm transportation capacity secured in the last Plan to expire and not be renewed consistent with the terms and provisions of the contract. This contract has been called the Elba Express capacity, and it is for 84,227 Dth/d. This will eliminate approximately $3.4 million in annual reservation costs from the gas supply portfolio.

**Q.** **Does this filing include provisions that were initiated in prior filed and approved Plans?**

A. Yes, this Plan includes the following carry over items as they are often referred to:

1. FINSS Utilization Enhancement provisions from the 2010-2013 plan will continue;

2. BPPSS discretionary call days totaling three (3) days will continue;

3. LNG top-off will continue to take place as late in the refill period as possible;

4. LNG Boiloff will continue to be an offset to the DSR so long as there is no vaporization from the peak shaving plants for daily operation. Additionally, nominating a de minimis amount of LNG supply for daily marketer obligations will not nullify boiloff decrementing a Marketer’s LNG inventory and such nominations shall be cancelled by AGL;

5. Access to the Macon LNG inventory for use in the Atlanta pool will continue consistent with the 2019-2022 CSP provisions;

6. CSS inventory transfer capacity that has been allowed for the past several plans shall continue so long as such transfer activity does not impede the Company’s ability to replenish inventory as needed for operational purposes;

7. The DSR change minimization provisions from the 2013-2016 CSP will continue; and

8. AGL will continue to host a post-winter review meeting after each heating season with the Marketers and Staff.

**Q.** **Does this conclude your pre-filed direct testimony?**

A. Yes, this concludes my pre-filed direct testimony at this time.

**Educational and Professional Background**

**Mr. Gregory Becker**

Mr. Becker received his Bachelor of Science Degree in Business Management with a concentration in Management Information systems from Southern Polytechnic State University. He received recognition for academic excellence by Delta Mu Delta, a national honors society for Management studies. Mr. Becker began his work in the natural gas industry in 1990 working as a Methods Analyst for National Fuel Gas in Buffalo, New York. In this role Mr. Becker was responsible for the daily reporting of the activities of all the shippers on National Fuel Gas’ interstate natural gas pipeline, National Fuel Gas Supply Corporation (“NFGSC”). Additionally, this role involved in-depth analysis of gas supply and pipeline transportation capacity offerings and services prior to pipeline unbundling. Mr. Becker was instrumental in NFGSC’s development and analytics surrounding the pipeline’s unbundling. Development of monthly PGAs in New York, annual gas cost filings in Pennsylvania and the preparation and submission of several Federal filing requirements were also a primary component of his work.

Mr. Becker left National Fuel Gas in early 1998 to join a newly formed company called New Energy Associates, LLC (“NewEnergy”) in Atlanta, Georgia. NewEnergy was formed by 3 principal investors in their buying the former Energy Management Associates business away from EDS Utilities Division. As a Senior Consultant, Mr. Becker worked in the Gas Strategy and Planning division of NewEnergy. He supported more than 50 North American clients in their use of the SENDOUT® gas planning application. Mr. Becker was primarily responsible for the software development agenda to ensure that it remained responsive to the needs and requirements of the evolving natural gas industry and strategic planning. Client engagements centered on development and deployment of cost-effective gas procurement strategies and gas supply portfolio design analysis. Mr. Becker was promoted to Lead Consultant and his role took on a more strategic focus in developing client partnerships to leverage his skills and experience to support natural gas client activities before their state or provincial regulatory agencies.

Mr. Becker joined AGL Resources in the spring of 2006 as a Senior Analyst. In this role he worked to develop standardized systems of interstate pipeline capacity contract tracking and reporting, guided the implementation of load forecasting software, and was instrumental in storage, transportation and gas supply contract negotiations for all the LDC business units within AGL Resources. He participated in the development of Atlanta Gas Light Company’s (“AGL”) 2007-2010 CSP and was the business lead on the 2010-2013, 2013-2016, 2016-2019, 2019-2022 and 2022-2025 CSPs.

He served as Project Manager for AGL’s Magnolia Pipeline project which developed a firm transportation path from Elba Island LNG facility to the Georgia market for a diverse source of gas supply. As Manager of Capacity Planning Mr. Becker led a team of analysts tending to the gas supply and capacity needs of the four utilities in Southern Company Gas. His primary duties included assessing the long-term gas supply reliability outlooks, evaluating load forecasting criteria for design, seasonal and annual demand forecasts, assisting in the setup of monthly gas supply and storage inventory management, oversight of capacity contracting on interstate pipelines, analysis of gas supply resources and assisting in development of company positions in FERC proceedings. In 2012 Mr. Becker was promoted to the Director of Capacity Planning. In this role Mr. Becker leads a team charged with load forecasting, contract negotiations, and developing and maintaining gas supply portfolios for each of the Southern Company Gas utilities that meet the needs of the system’s customers in a reliable, safe and cost-effective manner.