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Tennessee Public Utility Commission

Docket No. 22-00004

August 19, 2022

CHATTANOOGA GAS COMPANY
PETITION FOR APPROVAL OF TARIFF AMENDMENTS TO ITS T-1, T-2, AND T-3 TARIFFS

Rebuttal Testimony Of
Greg Becker and Chris Bellinger
On Behalf Of
Chattanooga Gas Company

I. INTRODUCTION

A. Panel Witness Greg Becker

Q. Please state your name, title, and by whom you are employed.

A. My name is Gregory Becker. I am Director, Capacity Planning for Southern Company Gas. I am testifying on behalf of Chattanooga Gas Company ("CGC" or the "Company").

Q. Please state your educational and professional background.

A. I have a Bachelor of Science Degree in Business Management with a concentration in Management Information systems from Southern Polytechnic State University. I began working in the natural gas industry in 1990 in Buffalo, New York. After working in several other companies, I joined what is today Southern Company Gas in 2006 as a Senior Gas Supply Analyst. In 2012, I was promoted to my current position where I lead a team charged with load forecasting, contract negotiations, and developing and maintaining gas supply portfolios for each of the Southern Company Gas utilities, including CGC. Additional information on my education and employment background is included in Exhibit GB-1.

Q. Mr. Becker, have you testified before the Tennessee Public Utility Commission ("Commission") in prior dockets?

A. I filed testimony in CGC's 2018 rate case in Docket 18-00017 regarding capacity planning issues that was later adopted by another witness on behalf of CGC. I also filed testimony in CGC's 2020 Docket 20-00139 regarding asset management sharing percentages.

Q. What are your job responsibilities as the Director of Capacity Planning for Chattanooga Gas Company?

A. My responsibility as Director, Capacity Planning is to oversee the development and maintenance of appropriate projections of natural gas consumption forecasts for firm customers of CGC. Those load projections range from how much natural gas will be needed on the coldest winter day, called a design day, where temperatures are anticipated to average just 8 degrees, through and including the warm summer days we are enjoying today. In all cases, the Company needs to stand ready to meet the needs of all our firm customers, day in and day out, today and for years to come, no matter what conditions come our way.

Additionally, the Capacity Planning department is charged with developing a cost-effective ability to deliver natural gas to the CGC system from upstream interstate pipelines that meets the needs of the system's firm customers in a safe and reliable manner for the load we project. This capacity planning function includes developing effective operational uses of on-system gas supply resources like the LNG plant. It includes consideration for the physical capabilities of the CGC distribution system and how it operates day-by-day on behalf of our firm and interruptible customers.

In all of this work, it is important for me to emphasize that for capacity planning purposes we take a wholistic view of the CGC system in terms of meeting the needs of our firm customers. As Mr. Bellinger and I will discuss later, this approach provides benefits to our non-firm or interruptible customers, but our obligation and our focus is on the firm customers as the Company has taken on the responsibility for ensuring that firm customers have the gas they need when they need it. Interruptible customers voluntarily choose to be responsible for their own gas supply and transportation up to its delivery to our gate station. This places interruptible customers in a very different position from our firm customers.

Q. What is the purpose of your testimony?

A. My testimony supports the Company's position on its ability to offer incremental sales or gas supply capability to interruptible transportation customers. The issue at hand is a request to use an extremely limited and highly integrated LNG facility, which is critical for system operations on the coldest of days, to provide incremental gas supply services to the interruptible transportation class of customers. The requested service is simply not an appropriate use of this facility and contrary to the supply obligation these interruptible customers voluntarily choose to accept when they elect to not be firm customers.

To be clear, all of CGC's customers are important. But the interruptible transportation customers are afforded an interruptible service primarily because the CGC system, *as a whole*, is constructed and maintained to meet the projected needs of our firm customers. The system, in its entirety, affords the opportunity for such interruptible service. It is inaccurate and incorrect to assume that any subset of the system can stand on its own to serve a specific customer or subset of customers.

The system works as an integrated network with an ability to meet the needs of our firm customers. That is how it is designed, built, and operated. Interruptible customers are afforded a level of service so long as it does not impede the Company's ability to meet our obligations to the firm customers. As CGC's system and its customer base has grown over the years, so too has our ability to provide interruptible customers with service.

However, at the extreme ends of our operations, especially on the coldest winter days, or on days where things just don't go according to plan for reasons beyond our control, the system and its aggregate gas supply capability is ultimately designed and operated to ensure the natural gas needs of firm our customers are met. The same is true of our delivering interstate pipelines, Southern Natural Gas Pipeline ("SNG") and East Tennessee Natural Gas ("ETNG"). The limitations and restrictions that these interstate pipelines place on shippers like CGC serving its firm customers are informative and contribute to the Company's ability to offer interruptible service to our customers. Interruptible customers are asked to go offline or switch over to their required back-up fuel source when needed, which is consistent with CGC's tariff for their class of service.

B. Panel Witness Chris Bellinger

Q. Mr. Bellinger, please state your name, title, and by whom you are employed.

A. My name is Chris Bellinger. I am the Gas Supply Manager – Southern Operations for Southern Company Gas, which includes gas supply management for CGC.

Q. Please state your educational and professional background.

A. I have my Bachelor of Business Administration in Finance from the University of Georgia. I have worked for Southern Company Gas for 17 years in the gas supply for Southern Operations, starting as an analyst and working my way up to my current manager position.

Q. Mr. Bellinger, have you testified before the Tennessee Public Utility Commission ("Commission") in prior dockets?

A. Yes, I provided rebuttal testimony in CGC's last rate case in Docket No. 18-00017 regarding certain customer-specific gas supply issues, including what has been referred to as the availability of "incremental" gas.

Q. What are your job responsibilities as the Gas Supply Manager for Chattanooga Gas Company?

A. I am responsible for managing the gas supply for CGC customers and other local gas distribution companies in the southern region of Southern Company Gas.

Q. What is the purpose of your testimony?

A. My testimony describes and supports the Company's position on its ability to offer incremental sales or gas supply capability to interruptible transportation customers. CGC should not be required to use the firm customers' assets to support and sell incremental gas to the interruptible transportation customers and effectively provide the interruptible transportation customers with firm service for free. The risks of operational harm to the system and economic harm to the firm customers by using the LNG facility and peak shaving inventory far outweigh the benefit of providing such service to the interruptible transportation customers. The CRMA testimony seems to suggest that interruptible transportation customers are only interested in avoiding the higher cost of being a firm customer. CGC's tariff provides firm service for any customer who wants and pays for firm service. The tariff also provides a T-2 rate schedule that allows for interruptible transportation service with firm gas supply back-up.

C. Exhibits and Schedules

Q. Do you have any exhibits associated with your testimony?

A. In addition to the education and employment history reflected in Exhibit GB-1, we are sponsoring Exhibit GB-2, CGC Preliminary Design Day Gas Supply Capability, and GB-3, Hourly System Load on Feb 16, 2021.

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.

D. Presentation of Panel Testimony

Q. Why is CGC presenting you as a panel with joint testimony?

A. Fundamentally, the issues of capacity planning and gas supply management are interconnected and interrelated. In order to facilitate both our presentation of relevant information to the Commission and to simplify any cross examination, it is more efficient for us to appear together as a panel. This is the best way to ensure that any questions the Commissioners, staff, or parties may have get answered directly by one or both of us, since often we both will have information responsive to a question. This effectively avoids duplication of questioning and the potential for one of us to defer to the other if we were to appear separately.

Q To whose testimony are you responding?

A. Our testimony addresses and rebuts the testimony offered by the three Chattanooga Regional Manufacturers Association ("CRMA") witnesses, the consultant Mr. James Crist (direct and supplemental direct testimony), Mr. John Edwards of Koch Foods, and Mr. Chance Donahue of Kordsa. The CRMA wants incremental transportation customers to have access to what they describe as "excess" or incremental gas supply from CGC, including the use of gas supplies held in CGC's LNG facility which Mr. Crist incorrectly calls incremental gas (Crist, page 14). As we will discuss in more detail, there is no "excess" gas supply, via the LNG facility or otherwise, that is available to the interruptible customers on the rates, terms, or conditions desired and requested by the CRMA.

Boiled down to its basics, the CRMA witnesses want a service for which they are unwilling to pay. The service these interruptible customers want is already offered by CGC – it's called firm service or interruptible with firm back-up. In essence, the CRMA is seeking firm service at interruptible rates, which does not work from a capacity planning or gas supply perspective, nor is it good public policy. To approve what they request would provide a disincentive to CGC's other large volume firm customers to take firm service, in favor of interruptible service. Firm service at interruptible rates would be a great deal – if you could get it. But utilities like CGC have class of service rules and regulations for a reason. The chaos that would result from allowing our large customers to get firm service at interruptible rates would have far reaching consequences for our other customers, especially the residential customers. Our ability to provide affordable and reliable service would be materially and adversely affected, with residential customers facing both significant rate increases and, more importantly, a potential loss in gas supply.

Q. How is this joint testimony organized?

A. Our joint testimony has two main areas. The first section provides important information on the capacity planning process and gas supply management considerations. From this information, the Commission can better understand how we treat the system, as a whole, for the benefit of our firm customers and what goes into the design, construction, and operation of the system. With this background information, we then address some of the specific points raised by the CRMA witnesses in their testimony.

II. BACKGROUND ON CAPACITY PLANNING AND GAS SUPPLY

Q What are some considerations that the Company evaluates as it looks to utilize its on system LNG plant?

A. First, it is necessary to clear up some misconceptions about the LNG facility. The LNG plant is not a large storage facility available to be utilized whenever someone wants to purchase gas. Rather, the on-system LNG plant is a peak shaving resource for the system. It is a reserve facility that is CGC's last call for natural gas available to firm customers on our system in high load operating scenarios. It also provides the last line of defense when things don't operate according to plan in other aspects of the physical equipment needed to deliver natural gas to the CGC system, for example, an interruption to the interstate pipeline, a gate station shutdown, an inadvertent construction mishap that cuts a pipe, or the negative operational and customer impacts suffered by the entire energy sector in the unprecedented winter of 2021 during Winter Storm Uri.

Second, it is also very important to understand that the LNG facility is not a ready access source of supply year-round. It has a very specific injection or liquefaction period each year. There is a defined maintenance period where the plant is shut in and unavailable for system supply support – maintaining such a critical operational resource is essential to CGC providing safe and reliable service for our customers. Our laser focus on readiness ensures that the LNG facility is available for sendout or vaporization of the stored LNG in a finite window of time in every heating season; generally speaking, that is late December through February. The LNG plant itself is staffed with at least two operators anytime there is possible need for sendout from the facility. The LNG plant has two operators on duty Monday through Friday from 9:00 AM to 3:00 PM. Outside that time, there is only one operator on duty and CGC must increase its personnel at the plant to vaporize LNG.

Third, the company appropriately considers economics. The cost of gas in the tank that is already liquified has value. That value is compared to the cost of buying, transporting, liquefying, and storing inventory at a point in time in the future. Liquefying natural gas adds a meaningful amount of cost to the process. In a heating season like 2021-2022 where prices in the market were trending higher, the cost of replacing inventory was in some instances at a higher cost than that of the inventory that could be taken out of the tank. In a scenario like that, sendout from the LNG tank is not in the best interest of the firm customers.

Q. If the LNG plant has such limited operational characteristics, why have it at all?

A. There are several things to remember. The plant was constructed a long time ago, and so most of the investment in the plant has long since been recovered in rates. Thus, the cost of the plant today to ratepayers is just the ongoing maintenance and operational costs, occasional needed improvements or upgrades, plus the necessary employees to operate the facility safely. Overall, this makes for a very affordable asset to maintain and have at the ready when it is needed.

CGC's overall place in the interstate pipeline network also makes having an LNG plant a very prudent expenditure. Relatively speaking, CGC is toward the end of each of the two major pipelines serving CGC. Moreover, the East Tennessee Pipeline that CGC mostly relies upon is fully subscribed. So even if CGC could purchase gas, getting it to CGC's system is very hard, especially on very cold days when demand is very high. The LNG facility provides an onsite gas resource that CGC fully controls independent of any other supply or transportation issues. That is a huge benefit to CGC's customers.

Finally, LNG affords a very flexible, immediate access gas supply service that meets the real-time load or gas consumption pattern of our customers. As such, it is an invaluable tool for our Gas Control team who is ultimately responsible for the operation of the system. Our firm customers' need is primarily driven by a response to cold weather. On those coldest of days, the expected consumption by our customers is at its highest. It is far more cost-effective to meet these short-lived high load periods of time with a peak shaving resource like LNG than to meet that same level of service by contracting for interstate pipeline service to provide that same aggregate daily capability for gas supply. In my nearly 20 years in CGC's Capacity Planning department, I've spoken to ETNG about potential incremental projects for added firm transport capacity numerous times. Their indicative rates were always in the range of \$1.00 to \$2.00 per Dth/day (dekatherms per day) for added pipeline capacity. The economic benefit of not having to buy such expensive incremental firm transport capacity and being able to meet the growing needs of our system's firm customers is both prudent and appropriate. A pipeline contract to replace just one half of the daily sendout of the LNG plant (60,000 Dth/day) would cost somewhere between $21.9 million to $43.8 million per year just for the ability to move the gas. The cost of the gas itself and the variable charges to get the gas delivered would be additional. CGC's use of the finite capability of the on-system LNG along with its procurement of interstate pipeline capacity, including the successful competitive bid for existing firm transport capacity on ETNG, are managed to best serve the economic interest of our customers and the energy needs of CGC's service territory.

The bottom line is that while the LNG facility is not an asset available every day to the Company, it is a vital operational component of the CGC system that must be maintained and managed to help ensure our ability to provide reliable and affordable gas to our firm customers when they need it most. An asset like this can help prevent a system failure like that experienced in Texas during Winter Storm Uri.

Q. In Mr. Edwards' testimony he compares operations at Koch's Morristown facility to their facilities in Chattanooga. Do you agree with his statements?

A. No, I do not agree. Chattanooga Gas is served by 2 interstate pipelines, Southern Natural Gas Pipeline ("SNG") and East Tennessee Natural Gas ("ETNG"). Both of these pipelines are fully subscribed. We are not aware of Atmos receiving service from SNG. When CGC establishes Operational Flow Order ("OFO") days, the company is evaluating the restrictions that one or both of these interstate pipelines may be placing on shippers. This would mean that a shipper served by a single pipeline could have fewer OFO days than a shipper like CGC that is served by two separate pipelines. This obviously impacts CGC's customers differently than might be the case for a local gas distribution utility like Atmos that may only be served by a single pipeline or that is taking firm delivery off of a completely different operating segment than the lateral serving CGC – a customer of CGC that has operations elsewhere in Tennessee and served by a different natural gas utility is likely going to have different OFO days from that utility than from CGC.

From a gas supply / operations perspective, Atmos takes firm delivery off of a completely different operating segment of ETNG than CGC does. It would be more surprising if the frequency of OFO days, across two discrete areas of the same pipeline, were to match up.

The deliveries made by SNG to the Chattanooga system happen at the terminal end of a lateral that runs south to north. The lateral originates in Cleburne County, Alabama. This lateral originates on SNG's North Main. This is the oldest section of the SNG system, and it operates at a lower delivering pressure than other parts of the SNG system. Moving gas to the farthest end of a lateral is physically challenging from a hydraulics perspective. It should not surprise any shipper that such configurations and operational challenges lead to OFO's to help safeguard their operations. In turn, CGC requires its transport customers to abide by the same limitations that the interstate pipelines are asking it to comply with. This is neither punitive in nature nor meant to extract penalty charges from CGC Interruptible

Transportation customers. CGC's Gas Control team would much rather have the right amount of natural gas being delivered to the system to meet the consumption by all our customers and to have everything be in balance. Delivery of dekatherms makes that work. Assessment of OFO penalty charges retrospectively does not help the system operate more efficiently.

III. SPECIFIC REBUTTAL

A. The LNG Plant, Excess Capacity, & Incremental Gas

Q. Beginning at page 18 of his direct testimony and page 8 of his supplemental direct testimony, Mr. Crist contends the LNG facility should be made available to transportation customers immediately and ongoing to meet their demand requirements and to reduce their gas costs. Do you agree with this position?

A. No. The transportation, storage, and peak shaving assets held by CGC are there to ensure the company has the ability to meet the natural gas needs of our firm customers in a safe and reliable manner. They are not secured with the intent to serve or support natural gas delivery for the system's non-firm customers or transportation customers electing interruptible service. The tariff defines the entitlements each customer's rate schedule affords them and CGC's obligations to provide such service to them. CGC's gas supply portfolio is not built with the expectation that it will supplement the interruptible transportation customer's gas supply requirements. CGC firm customers should not be expected to pay for a service which provides such a benefit to non-firm customers. If CGC did so, it would effectively be allowing interruptible customers to expect and benefit from a priority level of service that is paid for by firm customers. This would create a scenario where current firm customers are incentivized to switch to non-firm rate schedules. A customer would not choose firm service and therefore elect to pay higher service-related costs if they could be an interruptible customer, pay less, expect ready access to incremental gas, and thereby effectively enjoy the key benefits of firm service.

If the interruptible transportation customers want to have access to gas without the exposure to market rates, then they could receive service at the PGA rate simply by becoming a firm customer. What the interruptible transportation customers want is to pay lower rates year-round and then purchase gas from CGC whenever they choose to – especially in periods of time when it is difficult to secure flowing gas supply on the interstate pipelines. If these interruptible customers want to have more gas cost certainty, avoid curtailments, and enjoy the benefit of safe and reliable natural gas service, they should switch to firm service. That places the obligation to plan for and provide adequate gas supply, at any time of year, any time of month, any time of day, upon CGC.

Q. Mr. Crist also noted at page 18 of his direct testimony that CGC stopped all LNG sales from its LNG facility and has excluded this peak shaving asset from optimization activities by the asset manager. Why did CGC take this action?

A. The LNG facility is CGC's only peak shaving asset that is available for no-notice peak shaving use to serve firm customers on cold days when the company interstate pipeline capacity is not sufficient to meet CGC's firm customers' demand for natural gas. CGC's design day demand is forecasted to be 153,333 Dth/day. Of that amount, 112,018 Dth/day is available through interstate pipeline contracts, leaving 41,315 Dth/day to be supplied by the withdrawal of gas from the LNG facility. Mr. Crist's assertion that the amount of capacity held by the company "is in excess of what the Company has experienced, and has predicted what will be experienced in the future…" (see direct testimony at page 12) is simply not correct. While the table of annual throughput and peak day sendout figures on page 10 of his testimony may be historically accurate, none of these observations refute the validity of the Company's projected need for natural gas service when the system's firm customers experience a day with a mean temperature of just 8 degrees.

Cal. Year	Total	Date	Temps	HDDs
2011	111,569	01/12/2011	24.5	40.5
2012	103,146	02/11/2012	25.3	39.7
2013	92,985	11/27/2013	28.1	36.9
2014	134,821	01/06/2014	10.8	54.2
2015	126,499	02/19/2015	16.6	48.4
2016	115,823	01/18/2016	22.6	42.4
2017	108,038	01/07/2017	21	44
2018	129,424	01/17/2018	17.5	47.5
2019	108,713	11/12/2019	26.5	38.5
2020	110,983	01/20/2020	28	37
2021	118,020	02/16/2021	23.6	41.4
2022	102,434	01/21/2022	30.6	34.4

By expanding that same data table to include average temperature and its corresponding HDD value, as is shown above, it is clear that none of these observations are close to a Design Day weather expectation of an 8 degree average temperature.

Design day weather conditions do not happen very often. But when they do, the obligation to provide safe and reliable life-saving service to our customers is CGC's sole responsibility. Degrading that readiness because, *on average*, there has not been a design day is not the appropriate lens to view readiness for extreme weather events.

CGC's LNG facility also serves as a contingency supply in case there is a disruption on the system or in the event the interstate pipelines that serve CGC have operational issues that prevent them from delivering CGC's full contracted capacity. The LNG inventory, however, is finite and will only cover approximately 13 days of overall availability assuming full vaporization capability is used. Once LNG is withdrawn, during the finite window where it is available each heating season, the Company's ability to liquify and replace gas to be stored as LNG to be available again within that same heating season is extremely limited. It is not appropriate to allow an asset manager to utilize the LNG facility to make off-system sales to create margin while putting the system's firm customers at risk. It is even less so to make incremental gas sales available to meet the needs of interruptible transportation customers. The operating system's integrity on cold days or on those days when the interstate pipelines have operational issues is the critical operational need for CGC's LNG plant.

Each year, as CGC's firm customers' demand for natural gas service grows, the need to have LNG inventory available becomes increasingly more critical. Since CGC's 2018 rate case, the Company has been making major investments in its facilities to allow additional volumes of LNG to be sent out and used across a larger part of its system to meet firm customer demand. This investment has been vital to meeting the critical need to provide service to CGC's ever-growing firm customer base. Because of the finite amount of inventory, the limited window of time that it is available to send out or vaporize, the extremely limited amount of liquefaction capability there is, and the speculative nature of even being able to liquify and store natural gas in the midst of a heating season's cold weather, the LNG facility's gas supply capabilities must be maintained and appropriately guarded and should not and cannot be made available for optimization. On those coldest of winter days, our firm customers want safe and reliable service, and we are obligated to ensure that we have done the planning and managing so that the gas is available when requested. In this regard, the limited value that may be obtained through creating optimization value is meaningless.

Even though CGC can direct the asset manager to start or stop any optimization activity related to the management of its gas supply assets at any time, CGC does not believe it is prudent to engage in LNG sales given the long list of operational risks to which that it exposes our firm customers. Moreover, since it is not uncommon for some of these extreme cold days to occur late in the season, especially in February and March, it is always best to err on the side of retaining those LNG resources so you have them when you need them late in the season.

Q. Since CGC does not allow the asset manager to sell LNG from its peak shaving facility that would provide an economic benefit to the firm customers, should CGC sell LNG to interruptible transportation customers?

A. No. Interruptible transportation customers are responsible for arranging for their own gas supply requirements – both purchasing the gas and its transportation to CGC's system. And as such, they pay a lower tariff rate. CGC is more than willing and ready to take over these responsibilities for our customers if they become firm customers.

Q. Are there any other reasons for not selling incremental gas to these interruptible transport customers?

A. Yes. The tariff states that if CGC determines that incremental gas sales are available, it must sell the incremental gas at the applicable index rate plus variable pipeline charges. But selling at that rate provides incomplete cost recovery. That rate does not include all the related costs incurred to create and store LNG, let alone sell it to an interruptible transport customer. The costs should include pipeline demand charges for the firm transport capacity held by CGC to meet the requirements of our firm customers. It should also include all fuel charges, including the variable costs for transportation of the natural gas to the CGC system. It must also include all the costs incurred to convert the vapor natural gas to a liquid form for storage as LNG. The cost to vaporize that liquid and make it available for sendout into the CGC system is also a mandatory cost component. Without incorporating all these directly related costs in what would be charged for access to gas sold, the firm customers would clearly be subsidizing this interruptible class of customers and can only be harmed by CGC providing such sales.

Q. You have partially addressed this next question, but to be direct, can CGC provide incremental gas from its LNG facility year-round?

A. No. The facility must go offline each year for extended periods of time to perform routine maintenance, replacement or repair of essential equipment, and for us to perform periodic needed capital investments. These offline periods of time can last 4 months or more every year. There are other factors, such as unplanned maintenance and repairs at the plant that also impact availability. Then there are overall improvements within CGC's distribution system that cause constraints which prevent CGC from vaporizing LNG and delivering the gas into the system year-round. Given the operational issues, we focus on ensuring that this essential component of the operational readiness of the CGC system is available when we need it most, during the winter peak demand season.

Q. Can CGC's firm customers be harmed economically from the sale of incremental gas?

A. Yes. There are a number of situations where the sale of incremental gas can cause the firm customers economic harm, including, but not limited to, paying higher gas costs for replacement of the LNG potentially sold. Incremental gas sales would lower asset management guaranteed minimums paid to CGC which are an offset to firm customer billings. Allowing incremental gas sales would also reduce LNG inventory that could be used by the firm customers to offset high gas prices during a heating season.

If CGC sells incremental gas to the interruptible transportation customers, the incomplete price paid for that gas is determined by the published index price of gas for that day. As described above, that does not accurately reflect the true cost of that gas. Second, CGC does not have the personnel or resources to hedge the replacement gas for when the replacement gas must be purchased and ultimately liquefied for storage as LNG in the future month(s). Therefore, the future price of the replacement gas to make up for any incremental gas sold could be at a higher price and consequently increase the gas costs borne by CGC's firm customers.

The gas purchased to replace the incremental gas sold needs to be delivered to CGC's system on CGC's interstate transportation contracts. This replacement activity encumbers more of the interstate transportation assets that would otherwise not be used by CGC. The less assets the asset manager has available to it will in turn drive the potential value of the asset management deal down, resulting in lower annual fixed fees to be offered to CGC for management of its assets, and thereby decreasing the offset to firm customers in CGC's annual filings.

Incremental gas sales reduce the LNG inventory available to the firm customers that could otherwise be used to offset high gas prices. For example, in February of 2021, CGC used LNG instead of purchasing extremely high-priced gas due to a sustained period of cold weather brought on by Winter Storm Uri. By its practice of safeguarding the LNG inventory, CGC was prepared and had adequate LNG inventory needed to protect the firm customers from the unusually high resulting gas prices.

Q. What would be the impact on the LNG facility by utilizing it more often to facilitate the sale of incremental gas to interruptible transportation customers?

A. Generally, the operations and maintenance costs would increase to account for the increased usage. The equipment and systems used to liquefy and vaporize LNG would wear down sooner and need to be overhauled or replaced with greater frequency. For example, the turbine used to liquefy natural gas to LNG needs to be overhauled after a very finite amount of hourly usage. Greater utilization of the facility would create a higher frequency of overhauls. This in turn creates a large expense that is borne by the firm customers. To effectuate the sale of incremental gas to interruptible transport customers from the LNG facility, CGC would also require added company personnel to be on hand to perform the tasks required for the vaporization and liquefaction processes which adds even more costs to be recovered from firm customers.

Q. How would CGC be impacted operationally if it was required to provide incremental gas from its LNG facility?

A. The LNG facility is CGC's only peak shaving asset that is available for use to serve firm customers on cold days when the Company's interstate pipeline capacity is not sufficient to meet CGC's firm customers' demand for gas. The LNG facility also serves as a contingency supply in case there is a disruption on the interstate pipeline system serving CGC's system which could prevent CGC receiving its full contracted capacity. The LNG facility is also the last truly no-notice swing source of supply if the Company's forecast of customer requirements is too low or if the actual weather experienced by the system is colder than what had been forecasted for the day.

The LNG inventory is finite and will only last approximately 13 days assuming full vaporization capability is used. Once LNG is withdrawn during the heating season, the Company's ability to liquify and replace gas stored as LNG that may be needed during the remaining winter months is extremely limited and there is no guarantee that winter operational conditions will allow for liquefaction during the heating season. Because of the finite amount of inventory that can be stored at the LNG facility, and the lack of assurance that any gas withdrawn could be replenished through liquefaction activities during the current heating season before it is needed to provide the safe and reliable gas service required by CGC's firm customers, increased LNG usage to support the sale of incremental gas to interruptible transportation customers increases the operational risk of providing service to firm customers.

If CGC were to provide incremental sales to interruptible transportation customers, that would increase the liquefaction required in the subsequent summer period to replace the LNG inventory that was sold. That in turn cascades through the facility's maintenance schedules and increases the risk of not replenishing LNG inventory ahead of the next winter's heating season. The LNG facility must be held in reserve and should not be made available for the sale of incremental gas to interruptible transportation customers. The LNG facility and peak shaving inventory was never intended to be used as a supplemental gas supply source for the interruptible transportation customers.

B. Peak Day Usage and Gas Supply

Q. Mr. Crist in his direct testimony at page 12 and supplemental testimony at page 4 states that CGC currently has pipeline capacity of 116,917.0 Dth/day, which is in excess of the previously held 91,917.0 Dth/day in capacity. Do you agree with his calculation?

A. We agree with the math, but disagree with his conclusion that CGC now has excess natural gas supply capacity.

Q. Can you please explain how it is that with this additional capacity that CGC does not have excess capacity?

A. To fully understand this issue, we need to go back to the CGC 2018 rate case.

As CGC discussed in the 2018 rate case, CGC was facing the loss of 25,000 Dth/day in pipeline capacity. CGC obtained this capacity through a short-term capacity release from Oglethorpe Power that was going to expire on January 31, 2022, which was the same day that Oglethorpe's contract for the capacity on ETNG was set to end. After assessing the Company's options, we determined that what was called the Red Bank-Signal Mountain project would allow us to more fully utilize the LNG facility and offset some of the loss of interstate pipeline capacity.

In 2022, CGC was fortunately able to secure a total of 50,000 Dth/day of incremental pipeline capacity, which made up for the 25,000 Dth/day to be turned back at the end of the capacity release earlier this year, and which provided us with some additional and much needed durational firm transport capacity for future growth and to readdress the LNG plant's use. But it is not fair or reasonable to consider any of this 50,000 Dth/day as excess gas supply capacity.

Q. Please continue.

As we have discussed, our approach with capacity management and gas supply is wholistic – we have to look at the CGC system as an integrated whole for the purpose of serving our firm customers. In 2018, in committing the LNG plant for a wider potential use, because of a lack of available incremental pipeline capacity, we were potentially reducing our operational reserves to a very low level on those days when we might most need such reserves. It was a carefully considered business decision, trying to balance the growing needs of our firm customers with affordable and reliable service with the prospect of extremely cold days that place huge demands on the entire system in an area of the country with limited gas supply resources provided by two interstate pipelines that are fully subscribed. At that time, proceeding with a plan that intentionally projected an even greater use of the LNG plant was the only known option the company had.

Obtaining this 50,000 Dth/day capacity was a true once in a generation benefit. This 50,000 Dth/day offsets that 25,000 Dth/day we were to lose at the end of the capacity release term while affording CGC with the unique opportunity to reposition the on-system peak shaving resource – the LNG plant – back at the very top of the dispatch order and restore its original design intent. System Planning records indicate that the LNG plant has a maximum physical sendout capability of around 90,000 Dth/day. But the reality is the LNG plant was built for only a sendout of 60,000 Dth/day with a fully redundant second vaporization train. As such, securing the 50,000 Dth/day of pipeline capacity means we need to re-calibrate expectations. For years the LNG plant was looked at as a general supply resource out of convenience because it was in fact all that CGC could leverage. Now, CGC has a reasonably adequate level of firm transport to meet current system needs and future growth, a capacity acquisition process that took nearly 4 years to complete. Given what we have seen in extreme weather these last few years, we simply cannot bargain away our firm transportation capacity for a regulatory settlement that makes CGC become more reliant on the LNG plant once again.

Q. Do you have a graphical representation of CGC's gas supply that can assist us with visualizing these changes?

A. Yes. If you look at Exhibit GB-2, CGC Preliminary Design Day Gas Supply Capability, we have done a preliminary recalibration of the LNG plant from 91,630 Dth/day to 66,630 Dth/day and the available pipeline capacity. Net, our design day load projection for the 2022-23 heating season is only slightly greater than it was before the acquisition of the 50,000 Dth/day in pipeline capacity.

Q. Both Mr. Crist at page 17 of his direct testimony and page 6 of his supplemental direct testimony and Mr. Donahue in his testimony discuss how CGC, in failing to make incremental gas available to Kordsa in January 2022, cost Kordsa some $350,000 in additional gas charges. How do you respond to that?

A. Kordsa is a large, sophisticated gas customer that makes business decisions for the long term. It has elected to take interruptible service from CGC in lieu of firm service, or transportation with firm back-up service. It now benefits from a special contract rate with CGC which it has chosen to take in lieu of building a bypass facility. While Kordsa may have had to spend more on those days for gas and transportation than otherwise, most likely its aggregate costs are less than if it was a firm rate customer.

Q. At pages 17 and 18 of his direct testimony and page 7 of his supplemental direct testimony, Mr. Crist cites the Exeter Report and suggests that CGC does not sell incremental gas because not doing so benefits its affiliate Sequent, the asset manager. Do you agree with his characterization and conclusion?

A. No, and there are several problems with this testimony. First, the Exeter Report did not find that CGC did anything wrong or improper in not selling incremental gas. Second, Sequent is no longer an affiliate of CGC – Sequent was sold to Williams effective July 1, 2021, so this is simply not relevant anymore. Third, the Exeter Report did suggest a number of changes to the asset manager RFP process, most of which were adopted and implemented for the new asset manager agreement that took effect this year. Finally, the sharing percentage between CGC and its customers was recently changed from 50%/50% to 75%/25%, to the benefit of customers.

Q. As you are aware, there has been an agreement to transfer the incremental gas issue from Docket 22-00032, CGC's ARM Docket, to this docket. In connection with the incremental gas issue formerly in the ARM Docket, the CRMA filed a substantive response in opposition to CGC Motion to Strike of Transfer Certain Testimony to this docket. Have you reviewed this filing?

A. Yes, we have each reviewed it.

Q. In that CRMA pleading, the CRMA addresses the denial of a request for incremental gas that was made on January 6, 2022, and the CRMA alleges that CGC was diverting gas when CGC's customers needed and wanted that gas. Specifically, this pleading alleges:

Just five days later, CGC's asset manager began diverting large amounts of CGC's gas to non-jurisdictional buyers. Each day, from <u>January 11 through January 31, 2022</u>, the asset manager diverted 12,000 to 15,000 dekatherms of gas <u>that had been scheduled for delivery to CGC</u> and replaced it with gas from the Company's LNG tanks.[3] Between January 11 and 31, the asset manager sold a total of 122,000 dekatherms of gas to off-system buyers on the open market. None of it went to CGC's interruptible transportation customers who had asked for and needed the gas." (Emphasis added)

Did CGC's asset manager divert gas that had been scheduled for delivery to CGC as alleged?

A. No, absolutely not. CGC's asset manager did not divert gas that was scheduled for delivery to CGC. No gas scheduled for delivery on behalf of CGC was replaced with gas from the Company's LNG tanks. There is simply no basis for this assertion. All of the LNG vaporized by CGC in January 2022 was used solely to serve firm customer demand. The 122,000 dekatherms of LNG was used by CGC in accordance with its normal operating procedures and gas supply practices.

The Company determines if it will offer incremental gas to interruptible transportation customers after evaluating several factors, including, but not limited to, the time of the year or date within the winter period, the current LNG inventory, and if CGC forecasts it will vaporize LNG to serve the firm customers. In January 2022, based on these criteria, CGC determined it was too early in the winter season to offer incremental gas sales using peak shaving inventory from the LNG facility. While the January 6, 2022, request for incremental gas technically was made to the wrong person, CGC's response to the request for incremental gas from Chance Donahue explained these facts, and this email exchange was included in a CRMA discovery response.

Q. The discovery response you are referencing is CRMA's Response to CGC's Discovery Request No. 5 in the ARM Docket. Does this response support the allegation that gas was diverted?

A. No. The CRMA discovery response appears to be speculation on what could have happened. There is nothing in the response that addresses any gas scheduled for delivery to CGC being diverted. It is possible that the CRMA may have confused pipeline capacity with gas scheduled for delivery. The fact that CGC holds capacity for the transportation of gas on a pipeline does not mean that there has been any gas scheduled for delivery.

Q. Can you please further discuss how the LNG facility is managed as a part of CGC's larger obligation to ensure gas for firm customers as opposed to interruptible customers?

A. Yes. CGC uses its LNG inventory to serve its firm customers and maintain system integrity in a variety of ways based on a multitude of factors that impact its operations. I will identify some, but certainly not all, of the conditions in which CGC would use LNG.

First, the LNG facility and its peak shaving inventory are used to meet firm customer demand on days where the forecasted demand is greater than all the transportation assets CGC has in its portfolio of assets. When CGC has purchased gas to fill all its transportation assets and has determined it will use all of its no-notice storage gas, CGC will use LNG to meet that forecasted demand.

Second, under CGC's Asset Management Agreement (AMA) it is required to purchase its gas by 9:00 a.m. Eastern Time ("ET") each business day for the next day flow, on Fridays for weekend and Monday flow, and on the business day prior to a holiday. That means CGC is required to purchase gas at least one day ahead from when it will flow the gas to meet customer forecasted demand. CGC must also purchase the same volume of gas for each day on Fridays for weekend and Monday flow. So that means early on a Friday morning, CGC is reviewing weather forecasts and current operating conditions to establish how much natural gas to buy for Saturday, Sunday and Monday. Think of how many times you yourself have said – the weatherman missed it this weekend.

Here is an example of how this might work. If the demand forecast produced on Monday for Tuesday's gas day is 90,000 Dths, CGC will plan its gas supply setup accordingly by purchasing gas to fill its transportation contracts, withdrawing gas from its Tennessee Gas Pipeline storages to flow on its transportation contracts, determine how much gas it will burn from its no-notice storage and, if required, how much LNG it will use. On Tuesday, if the demand forecast has increased to 100,000 Dths due to the temperature being colder than forecasted the prior day, CGC may be required to use LNG to meet the increased demand. If CGC wanted to buy gas intraday (buy and flow on the same day) to fill its unused transportation contracts it would most likely pay a very high price for that incremental amount of gas, if it is even available, and still may not be able to schedule the gas on the pipeline due to pipeline scheduling restrictions spelled out in their respective FERC-approved tariffs. The surest and most cost-effective approach is for CGC to use LNG to meet the increased demand.

Third, CGC may be required to use LNG at certain times within the gas day when customer demand requires it to maintain system pressures and not lose customers. As shown on Exhibit GB-3, during a 24-hour gas day, temperatures and customer demand swing up and down hour-by-hour. Load on the system is highest in the morning hours as people and businesses prepare for the day and again in the early evening when they return home, cook meals and other such things. Likewise, the early morning hours and later evening hours are typically to coolest times of day and would result in higher demand from customers than the middle of a clear sunny winter afternoon. CGC may be required to use LNG when the gas day's forecasted demand did not project its usage to cover these intuitive ebbs and flows in customer consumption.

Fourth, since CGC is required to buy gas on Fridays for weekend and Monday flow, there may be large differences in the forecasted customer demand for Saturday versus Monday or Sunday versus Monday, etc. CGC, from time to time, may find itself in the position where if it purchased all the gas required to meet Monday's gas day demand then it would have too much gas and be extremely over supplied on Saturday and Sunday's gas days. For a weekend's three-day purchase period, CGC is required to purchase the same volume of gas for each day. The potential amount of over supplied gas on one or two of those days can be extremely large and easily exceed 64,000 Dths per day. The cost of buying gas that we would not need would be borne by the firm customers.

For example, On December 30, 2021, the forecasted demand for CGC on Saturday, January 1, 2022, was 26,000 Dths; the forested demand for Sunday, January 2, 2022, was 85,000 Dths; and the forecasted demand for Monday, January 3, 2022, was 90,000 Dths. The actual large demand forecast variation over this particular weekend period forced CGC to reduce its gas purchases and use LNG to meet a portion of Monday's gas day demand.

Further complicating this situation was the fact that the New Year's Day holiday was to be recognized on Friday, December 31, 2021. This meant that CGC was required to purchase gas on December 30, 2021, for January 1-3, 2022. This requirement added another day for potential weather variability and changes in the forecasted demand. Thus, the December 31, 2021, demand forecast increased the Monday, January 3, 2022, demand to 95,000 Dths while the Saturday, January 1, 2022, forecasted demand remained unchanged at 26,000 Dths. This increased the demand difference on Saturday and Monday from 64,000 Dth (Monday's projected load of 90,000 less the 26,000 low load on Saturday to buy for) to 69,000 Dths (Monday's projected load of 95,000 ahead of the New Year's holiday less the 26,000 low load on Saturday to buy for).

The bottom line here is that managing the gas supply for CGC's firm customers is very complicated, with a number of different factors needing to be taken into account. When you then layer on the timeframes for when gas must be purchased, something as simple as a long holiday weekend requires immense planning and consideration of a number of variables. Preserving the limited capacity of the LNG facility to address these variables to ensure gas supply for our firm customers must be our primary and only purpose for the LNG gas. To require CGC to make LNG gas available on the day of a request for gas, which is what was requested on January 6, 2022, would have had significant adverse consequences on our ability to serve firm customers.

Q. Do you agree that Exeter should investigate CGC's incremental gas practices in its next audit?

A. As Mr. Hickerson addresses in more detail, it is already built into the triennial review process for the auditor to review CGC's capacity planning and gas supply actions. Whether anything different should be done on the next audit is ultimately for the Commission to decide. But given our practices and Exeter's past findings validating our actions, in our opinion it is unnecessary to conduct the type of audit that the CRMA is requesting.

IV. CONCLUSION

Q. Do you have any concluding remarks regarding CGC's capacity planning and gas supply?

A. CGC has an obligation to provide reliable and affordable natural gas service to its *firm* customers. Customers who elect to take interruptible service *choose* to give up CGC providing reliable and affordable service – it is a business decision interruptible customers make that over time being responsible for their own gas supply and transportation will be cheaper than receiving those services from CGC. If those interruptible customers are unhappy with what they have chosen, then they can easily switch to firm service or transportation with firm back-up. But in any case, it is not CGC's duty or obligation to augment interruptible customer's service in a way that better aligns it with firm service at an interruptible rate.

In terms of how CGC manages its gas and transportation assets, it is a very complex calculus that must be undertaken to ensure that on any given day, regardless of the weather, and in view of the variety of issues that are impacting the interstate transportation system on any given day, CGC is able to meet its firm customers' demands for natural gas service. After maxing out our resources over the last couple of years in the face of an ever-growing demand, CGC is in the best position in years to ensure that it can meet its reliability and affordability obligations to firm customers. We never want our customers to face what many in Texas had to deal with in February 2021.

Q. Are you saying that CGC will never provide incremental gas to interruptible customers?

A. No. But the availability of gas on any given day will be a function of where we are in the winter season and many different factors that require the exercise of judgment based upon experience. To mandate that we provide incremental gas on the terms that CRMA is now seeking is contrary to good public policy and sound utility management.

Q. Does this conclude your joint rebuttal testimony?

A. Yes, it does.

<u>Educational and Professional Background</u>

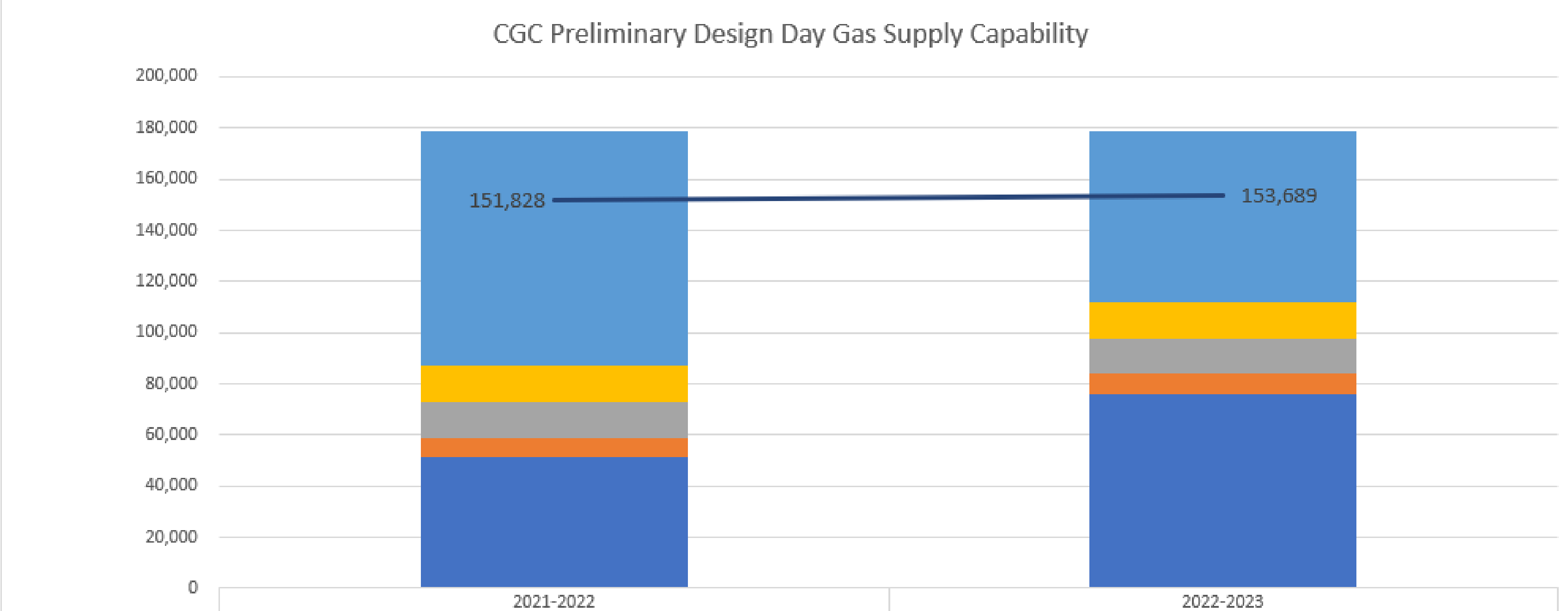
Mr. Gregory Becker

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 PGA's 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.

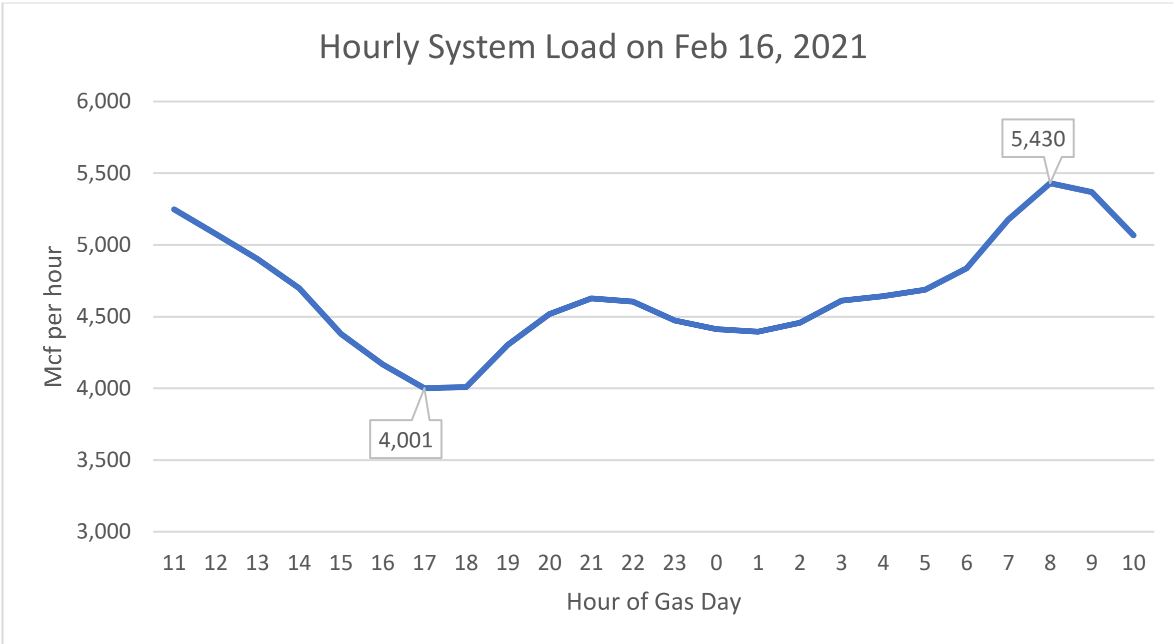
Mr. Becker left National Fuel Gas in early 1998 to join a newly formed company called New Energy Associates, LLC ("NewEnergy") in Atlanta, Georgia. NewEnergy was formed by 3 principal investors in their buying the former Energy Management Associates business away from EDS Utilities Division. As a Senior 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 Gas Supply 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 been 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 Capacity Supply Plan and was the business lead on the 2010-2013, 2013-2016, 2016-2019, and 2019-2022 Capacity Supply Plans.

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 leads a team of analysts tending to the gas supply and capacity needs of the 4 utilities in Southern Company Gas. His primary duties include 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.



	2021-2022	2022-2023
LNG	91,630	66,630
CSS	14,346	14,346
FS-PA	13,659	13,659
FS-MA	7,741	7,741
Firm Transport	51,272	76,272
Design Day Load	151,828	153,689


Hourly System Load on Feb 16, 2021
6,000
5,500
5,000
4,500
4,000
3,500
3,000
Mcf per hour
5,430
4,001
11 12 13 14 15 16 17 18 19 20 21 22 23 0 1 2 3 4 5 6 7 8 9 10
Hour of Gas Day