Atlanta Gas Light

INTEGRATED CAPACITY AND DELIVERY PLAN

2022-2031

Docket No. 43820

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ATLANTA GAS LIGHT
INTEGRATED CAPACITY AND DELIVERY PLAN
2022-2031
DOCKET NO. 43820

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2022 INTEGRATED CAPACITY AND DELIVERY PLAN TABLE OF CONTENTS

List of Figures:

List of Tables:

CHAPTER 1. EXECUTIVE SUMMARY

1.1. Description and Purpose of AGL's Integrated Capacity and Delivery Plan

Atlanta Gas Light Company ("AGL" or the "Company") files this 2022 Integrated Capacity and Delivery Plan ("i-CDP", or the "Plan") with the Georgia Public Service Commission (the "Commission" or "GPSC") in compliance with the Commission's February 23, 2021 Order in Docket No. 42315 ("i-CDP Order"), which adopted the stipulation of the GPSC Staff ("Staff") and AGL establishing a long-range comprehensive planning process (the "Stipulation"). The Order requires the filing of an i-CDP at least every three years. The i-CDP is AGL's ten-year plan to serve the natural gas needs of AGL's customers in a safe, reliable, affordable and clean manner. The Plan is a comprehensive process for the Commission to review the Company's proposed projects and programs, including capital and certain related operations and maintenance ("O&M") spending requirements, in advance of the Company's related ratemaking proceedings such as the annual Georgia Rate Adjustment Mechanism ("GRAM"). Section 3 of the Stipulation between the Staff and AGL includes a listing of Minimum Filing Requirements ("MFRs") for both the System Reinforcement Rider ("SRR") [1] and the GRAM capital projects. [2] The information included within this Plan document supplement the MFRs filed herewith to ensure that all of the agreed-to minimum filing requirements are met.

This filing: includes a thorough description of the Plan along with the key drivers and benefits of the Plan; demonstrates the Company's robust planning process; provides solid support for the Plan; provides an informative resource to Commissioners, Staff and other parties; includes a request for approval of the Plan and the associated parameters for capital budgets; and includes a request for approval of a rate amount for the SRR.[3] The Plan also reflects the remaining years

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[1] *See* Stipulation at 7-8, § 3(B) ("Minimum i-CDP filing Requirements for Capital Projects that Improve Pressure or Provide System Reinforcement and that are to be Included within the SRR.").

[2] *See* Stipulation at 9, § 3(B) ("Minimum i-CDP filing Requirements for Capital Projects to be Included for Consideration within Subsequent Annual GRAM Filings.").

[3] The SRR is a ratemaking mechanism described in the i-CDP Order for the purpose of recovering costs of specific, unique projects and programs in the Plan.

of the currently approved Capacity Supply Plan ("CSP") (Docket No. 42317) and is based on an updated ten-year forecast of customer demand.[4]

The purpose of the i-CDP is to provide a single, comprehensive planning and review process in which the parameters for subsequent CSPs, GRAMs, and SRRs can be established. The comprehensive planning process of the i-CDP is in addition to processes for CSPs as required by Georgia statute and Commission approved MFRs and GRAMs as required by Commission Orders and approved Tariffs currently in effect. The i-CDP does not replace the CSP or GRAM processes, but rather ensures consistency and continuity for the forecasts, assumptions, selected options, and other planning parameters that are currently presented and approved within the independent CSP and GRAM processes.

1.2. Summary and Benefits of AGL's Integrated Capacity and Delivery Plan

The AGL natural gas system has served Georgia well for 165 years, providing valuable energy for space heating, water heating, cooking, agricultural processes, and industrial processes. Natural gas remains a clean, low-cost fuel for the future, and as the world around us continues to change, AGL continues to plan carefully for the future and continues to improve its delivery system. AGL's Plan is necessary to maintain and improve a safe, reliable, affordable, and clean natural gas delivery system and facilitate economic growth for the benefit of all customers and residents of Georgia. The Plan includes a series of ongoing and proposed pipeline safety, reliability, and growth programs and describes the need for the programs and the expenditures necessary to implement the programs. AGL's Plan will continue to improve safety and reliability while keeping rates competitive compared to southeast local distribution companies ("LDCs").

The Plan builds on past successes and good decisions by the Company and the Commission. AGL, Staff, the Commission, and AGL's customers have worked together to create a safer and more reliable natural gas utility, and the Company must continue to make investments to maintain

[4] AGL's CSPs shall continue to be the dockets that: specify the range of the requirements to be supplied by interstate capacity assets; describe the array of interstate capacity assets selected by the electing distribution company to meet such requirements; describe the criteria of the electing distribution company (the "EDC") for entering into contracts under such array of interstate capacity assets from time to time to meet such requirements; and specify the portion of the interstate capacity assets which must be retained and utilized by the electing distribution company in order to manage and operate its system. An "updated forecast" does not necessarily indicate that a CSP Amendment is necessary or appropriate. If a CSP Amendment were to be required, it would be proposed within the existing CSP docket, not the i-CDP docket.

and improve the gas system for the future. AGL intends to continue working with the Commission to "stay ahead of the curve." The common goals and visions shared by AGL and the Commission through programs such as those proposed in the Plan have put AGL well on the way towards replacing aging infrastructure, ahead of many LDCs in other states. The Commission also has worked constructively for many years on its long-range plans through the Integrated Resource Plan ("IRP") process for other regulated utilities. Similarly, AGL expects the advanced engagement and communication with the Commission on long-range plans prior to its Annual GRAM Filings will create positive benefits for customers, the Commission, the Company, and other stakeholders.

While the Plan will address the challenges of aging pipes and compliance with safety requirements, the proposed investments will also support job creation and economic growth in Georgia. The need for significant additional investments in the system extends for the foreseeable future. The strategy includes investments in aging pipe replacement, several important safety programs, system reinforcement in counties that have experienced significant population growth, and new liquefied natural gas ("LNG") facilities. By capitalizing now on the opportunity created by low natural gas prices for the foreseeable future, the Company's Plan can create significant benefits of improved safety, reliability, environmental stewardship, and economic growth for many years ahead while maintaining competitive rates for customers.

In summary, the Plan includes:

- Forecasts of customers' needs for the 10-year period covered by the Plan
- A 10-year forecast of interstate and intrastate capacity asset requirements
- A 10-year projection of capital budgets and related O&M spending[5]
- Proposed pipeline safety and reliability programs
- Proposed projects to meet future customer demand for natural gas

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[5] The Stipulation approved by this Commission does not require all O&M budgets to be set forth or approved within an i-CDP filing. Indeed, Section 7 of the Commission-approved Stipulation states that the GRAM mechanism (as it currently is approved or as it is subsequently modified by agreement or by Commission order) will continue to address annual O&M and capital needs (other than the revenue requirements addressed through the SRR and the future revenue requirements that will be accounted for by the LNG Tracker for LNG-related assets not yet in service). The requirement to establish budgets within the i-CDP proceedings is for multiple year capital budgets and *related* O&M spending. To the extent that incurring related O&M is a natural consequence of following an approved capital budget Plan, disclosing the related O&M spending is needed to establish the true size and scope of the associated revenue requirement.

- Customer retention and growth programs
- Best practices (emerging industry techniques and regulatory preferences)
- Environmentally-focused initiatives

The key benefits of the Plan and this planning process are:

- Alignment of plans for the required array of interstate assets with the plans for intrastate assets to complete the transportation and distribution of natural gas to meet customers' needs
- Adequate planning horizons (3-year and 10-year views) to accommodate time to scope, design, engineer, authorize, and construct projects to meet customers' needs
- Continued improvements in safety for customers and others within Georgia
- Continued improvements in reliability for customers
- Enhanced environmental initiatives
- Transparency in the planning goals and objectives
- Opportunities for enhanced appropriate regulatory oversight
- Continued increases in economic growth and job creation
- Continuity in the forecasts used within CSPs and GRAM filings
- Support for rate stability, gradualism, and fair rates
- Preservation of competitive rates for customers

1.3. Key Drivers, Significant Events, Government Decisions and Market Conditions

The leading, high-level driver of the Plan is to meet AGL customers' needs and the community's needs for a safe, reliable, affordable, and clean natural gas delivery system and facilitate economic growth for the benefit of all customers and residents of Georgia.

The most significant recent event affecting the Company and the entire society is the COVID-19 pandemic. The effect on the economy has been significant (e.g., less demand for certain products and services and numerous business closings). While it has affected near-term growth in the number of AGL customers, the Company expects a full economic recovery and return to normal in the years to come. Additionally, due to other drivers described below, the need for many of the proposed projects and budgets in the i-CDP is independent of changes in future growth.

One very significant driver of the proposed Plan is aging pipelines that need to be replaced. As detailed further in section 5.11, there are thousands of miles of pipe, some of which is greater than

60 years old, that need to be replaced to mitigate risks to safety and reliability. The following table shows current miles of main that is aging and needs to be replaced.

Figure 1: Mileage of Aging Pipelines

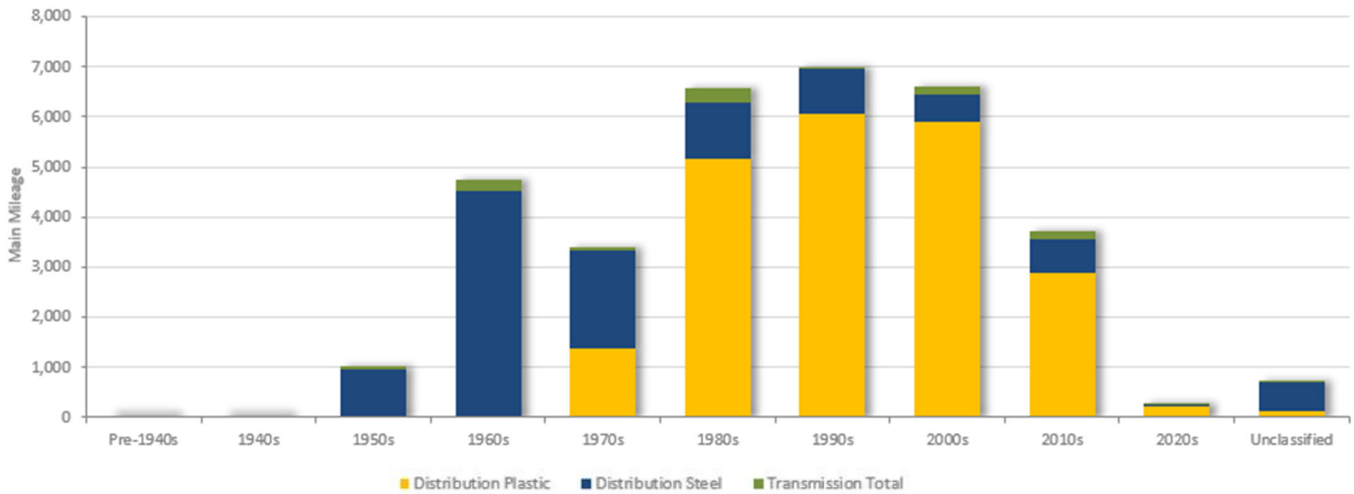


Table 1: Mileage of Aging Pipelines

Facility Type (miles)	Steel Unknown Install Date	Vintage Steel Pre - 1960	Mid-Vintage Steel 1960 - 1970	Modern Steel 1970 - 2019
Main	592.27	954.72	4885.53	4853.95
	Plastic Unknown Install Date	**Early Vintage Plastic Pre - 1974**	**Mid-Vintage Plastic 1974 - 1983**	**Modern Plastic 1984 - 2019**
Main	120.95	0.02	2463.54	19111.57

Several government decisions will significantly influence this Plan and future i-CDPs. For example, in October 2019, the federal government released its Pipeline and Hazardous Materials Safety Administration ("PHMSA") rule requiring Operators to reconfirm the Maximum Allowable Operating Pressures ("MAOPs") of its transmission pipelines, and compliance will result in significant cost to the Company. Additional proposed requirements by the federal and state governments are discussed in Chapter 5.

AGL is proud to support the communities it serves and is committed to preserving and protecting the environment. In addition to complying with applicable environmental regulations and reducing the Company's impact on the environment through stewardship, AGL recognizes that an increasing focus on climate by customers, policy makers, and other stakeholders requires that that the Company continue to seek new opportunities to reduce greenhouse gas emissions within AGL's operations and to support customers in addressing their sustainability goals through the use of natural gas. Indeed, some economic development opportunities are foreclosed if the potential sites do not offer established criteria for corporate responsibility. Natural gas is cleaner, safer, and easier to store than other fossil fuels. Nonetheless, to continue to provide the fuel of choice, the natural gas industry must demonstrate its commitment to ensuring that natural gas production, transmission, storage, distribution, and consumption is as environmentally friendly as possible. Specific information regarding AGL's efforts on greenhouse gas emissions reduction, sustainability, and support renewable energy are further described in Chapter 8.

When the General Assembly first enacted in 1997 the portion of the Natural Gas Competition and Deregulation Act that was subsequently codified as O.C.G.A. § 46-4-155 establishing CSPs, a realistic timeline for an interstate natural gas project approval was in the range of 12 to 18 months. Increasing complexities in the filing requirements, more stringent requirements for studies and analysis, and many other factors have meaningfully lengthened those project approval timelines. Project approval timelines have gone from 12 to 18 months to now a normalized expectation of 3 years and often longer. Infrastructure projects for the natural gas industry have been challenged to meet an ever-increasing threshold to obtain regulatory and environmental approvals. In 1997, with a 12-to-18-month approval timeline expectation, the 3-year CSP planning horizon was workable. In today's environment, a longer-term view is imperative.

The first days of the presidential term have seen a meaningful number of executive orders focused on removing, repealing, or redirecting those of the previous administration. The net effect appears to be a renewed diligence regarding potential climate influences. The totality of these changes will take time to be fully absorbed by the industry, project sponsors, and project customers. It seems reasonable to expect no short of a project approval timeline in the foreseeable future. It seems reasonable to assume that new mandates will not shorten planning or permitting schedules.

In the midst of changing circumstances, changing governmental regulations, and changing market conditions, the Company has created a Plan that addresses customer needs and requirements in a best cost manner while keeping rates competitive and affordable. As provided for in the stipulation approved by this Commission, greater Plan detail is provided for the initial 3 years of the planning period.

1.4. Comparison to Other Long-Term Planning Processes

The Commission and Company have worked well together in the past on planning and investment programs such as the Georgia Strategic Infrastructure and Development Enhancement ("STRIDE") program, Integrated System Reinforcement Program ("i-SRP"), and the Pipeline Replacement Program ("PRP"). While those processes and programs were very successful in bringing benefits to customers in a well-planned and affordable manner, they focused on specific project needs and spending, whereas this i-CDP process, in combination with Annual GRAM Filings and CSPs, facilitates a much more comprehensive and perpetual Commission review of and engagement in the Company's long-term planning process. The i-CDP is similar to the former STRIDE program, in that a 3-year SRR proposal is reviewed and a rate for SRR-funded projects will be established. Likewise, the review and audit processes for i-CDP are very similar to the review and audit process used for STRIDE and for the previous PRP. The proposed ratemaking mechanisms in i-CDP and STRIDE have similarities: STRIDE used a rate rider to facilitate cost recovery of important system reinforcement and aging pipeline replacement investments, and this i-CDP includes a proposal to do a similar thing, i.e., create a rate rider to recover costs of important system reinforcement projects. The proposed i-CDP's SRR reflects an improved rate design for customers compared to the STRIDE rate design, because it will better align each individual customer's payment to the cost caused by each individual customer.

While the i-CDP process is not the same as an IRP, the process will have some similarities to the regular IRP process with which the Commission is already familiar. That is, every three years, the Commission will have the opportunity to thoroughly review AGL's comprehensive long-term plans, benefits, and costs prior to its regular rate review process.

1.5. System Reinforcement Rider ("SRR")

According to the i-CDP Order, AGL shall be allowed to propose for recovery through the SRR the capital costs of Commission-approved property additions and improvements (collectively "SRR-funded assets") associated with large pressure improvement[6] and system reliability projects. Projects that fall into this category will not be included in the calculations for the Annual GRAM

[6] While larger pressure improvements are included within the SRR-funded projects, smaller pressure improvement projects will continue to be GRAM-funded. Lower-pressure, shorter-duration pressure improvement activity will continue to be presented within Annual GRAM Filings.

Filing. Based on the total cost of the SRR assets detailed in Chapter 5, the revenue requirements for the SRR are show in MFR-SRR-4. The Company has provided two options for an initial SRR rate to be effective January 1, 2022. Option 1, which is the Company's recommended rate option, is designed to have a rate in place at the end of year 3 of the SRR (2024) that will approximate the revenue requirement at the end of 2024. Additionally, due to the timing of the SRR eligible projects and their estimated date in service, the Company is proposing to over recover during the initial three year period to further mitigate the rate impact in 2025 when the SRR surcharge and rate base is rolled into the 2025 GRAM filing. Under Option 1, an annual SRR billing rate of $3.00 per Dth, or a monthly rate of $0.25 per Dth, is proposed to be effective January 1, 2022 through December 31, 2024. Option 2 is a rate that simply recovers the revenue requirement of the SRR by the end of 2024, similar to rider programs AGL has had in place previously. Additionally, both options include estimated rate increases for the duration of the 10 year i-CDP every three years. These rate increases and over or under recoveries are for illustrative purposes only since the SRR will reset every three years in accordance with the i-CDP program. Under Option 2, an annual SRR billing rate of $1.20 per Dth, or a monthly rate of $0.10 per Dth, is proposed to be effective January 1, 2022 through December 31, 2024.

The SRR charge for each customer will be a simple addition to the bill that is equal to the SRR Billing Rate multiplied by the customer's DDDC amount (in dekatherms). This is the same rate structure approach as several existing rates approved by the Commission: Peaking Services ("PS" rates), Franchise Recovery ("FR" rider) and Environmental Response Cost ("ERC" rider). For example, if a customer's DDDC = 1.3, and the SRR rate is $0.25, the customer's monthly SRR charge would be $0.33. The proposed rate design of the SRR will better align each individual customer's payment to the cost caused by each individual customer. The Company has included a proposed SRR tariff sheet as presented in Attachment A. As described in the i-CDP Order, the SRR charge will "reset" as new SRR projects are approved in new i-CDP Orders.

1.6. Request for Approval

The 2022 i-CDP sets forth a comprehensive plan that complies with the Commission's Order, and shows the Company's Plan to continue to provide customers with safe, reliable, affordable, and clean natural gas service to meet the demands of its customers and the state of Georgia as its population and economy continue to grow. As such, the Company seeks approval of the 2022 i-CDP and associated Action Plan contained in Chapter 9, including the following:

1. The forecast, as presented in Chapter 4;

2. The infrastructure delivery plan, as presented in Chapter 5, and associated parameters for capital budgets including the total capital expenditures for the first three years of the Plan, as well as historical spend for reference, shown in Table 1 below;

Table 2: Total Capital Expenditures ($ millions)

AGL Actual / Proposed Capital Investments ($ millions) (Includes OH, AFUDC, and Allocations)	2017	2018	2019	2020	2021	2022	2023	2024
	458.9	372.2	373.6	475.6	456.2	513.0	595.6	604.1
	2025	2026	2027	2028	2029	2030	2031	
	554.5	521.7	527.6	533.4	539.2	545.4	550.8	

3. The construction of an additional LNG tank and associated facilities at the Cherokee LNG facility;

4. The programs and action plans requiring the related O&M expenditures as described below in Table 3;

Table 3: Total Related O&M Expenditures ($ millions)

AGL Actual / Proposed Related O&M Expenditures ($ millions)	2018	2019	2020	2021	2022	2023	2024
	4.8	3.8	9.9	11.5	19.7	21	22
	2025	2026	2027	2028	2029	2030	2031
	22.1	22.4	22.1	22.1	22.4	22.1	21

5. The programs and action plans for best practices described in Chapter 6;

6. The SRR revenue requirements as presented in MFR-SRR-4;

7. The monthly SRR charge of $0.25 per DDDC;

8. The SRR tariff sheet and billing rate, as presented in Attachment A;

CHAPTER 2. COMPANY AND NATURAL GAS SYSTEM OVERVIEW

2.1. Company Information

AGL delivers safe, reliable, affordable, and clean natural gas to approximately 1.7 million customers in Georgia. AGL has been in continuous operation as a natural gas LDC since 1855 and is the largest LDC in the southeast United States. The Company has been a trustworthy source of energy and a constant partner to the communities it serves. In 2016, AGL became a part of Southern Company. Listed below are additional facts and statistics about the Company:

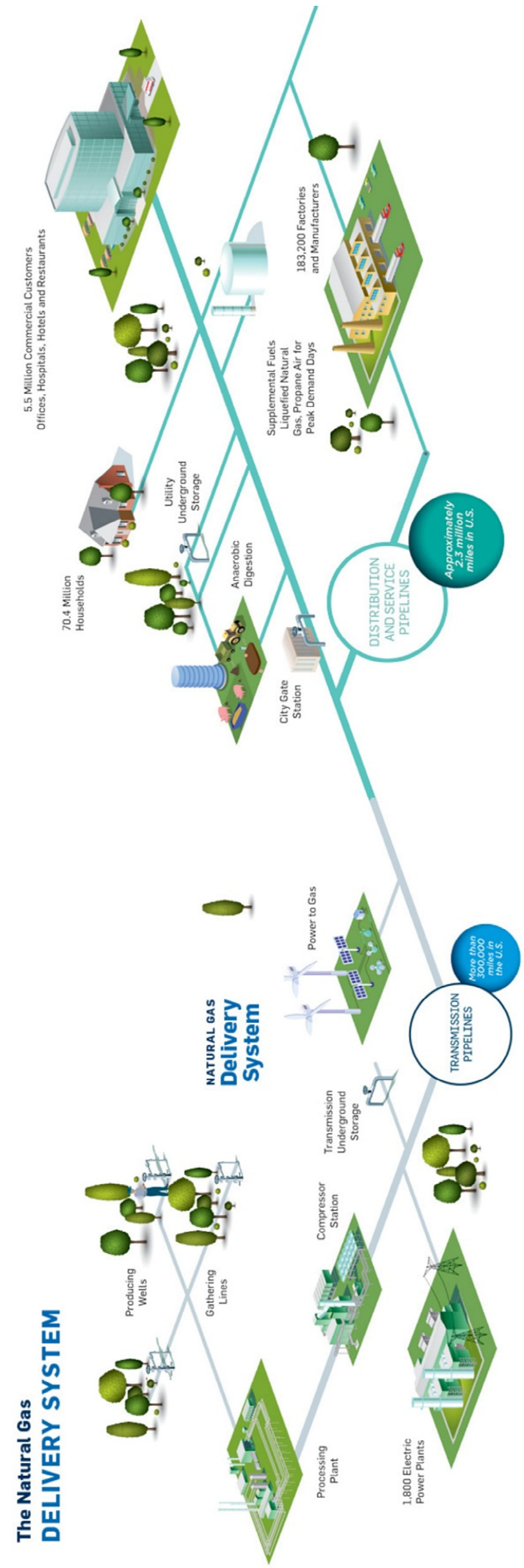
- Largest natural gas LDC service territory – 26,650 sq. miles
- 98 Georgia counties and 243 municipalities served
- 25 service locations
- 34,000 miles of distribution and transmission pipeline mains
- 1,000 miles of transmission pipeline
- 4,400 regulator stations
- 3 Liquefied Natural Gas (LNG) facilities – Cherokee, Riverdale, Macon
- 17 Compressed Natural Gas (CNG) stations
- 6.1 Bcf storage capacity
- 983 employees
- 17 certified natural gas marketers served in Georgia's unique competitive customer choice model
- First natural gas utility in nation to complete the replacement of all bare steel/cast iron pipe in its system (2,712 miles)
- Among the first natural gas utilities to begin to address the replacement of early vintage plastic pipe in its system (756 miles replaced in the first phase)
- AGL serves more than 1.6 customers in Georgia
- AGL delivered approximately 145,100 million cubic feet of annual firm load in 2020

2.2. Natural Gas System

Since 1998, AGL has operated under Georgia's Natural Gas Competition and Deregulation Act. Multiple Commission-certificated natural gas Marketers compete for customers and sell natural gas to customers while AGL distributes the natural gas to customers. Marketers' responsibilities include: processing customer service requests with AGL, billing customers for natural gas service (including the AGL base charges), buying natural gas to sell to residential and commercial customers throughout Georgia, and assisting customers with questions about billing, programs, and services. AGL's responsibilities include: performing service requests (turn customer's gas service on or off as requested by Marketers); meter reading; responding to gas emergencies; forecasting firm customers' loads; contracting for interstate assets to serve end-use customers; allocating the array of interstate assets to Marketers based on their firm customers' needs; and building and maintaining the intrastate natural gas pipeline and distribution system.

An illustration of the natural gas delivery system is shown in Figure 2 on the following page.

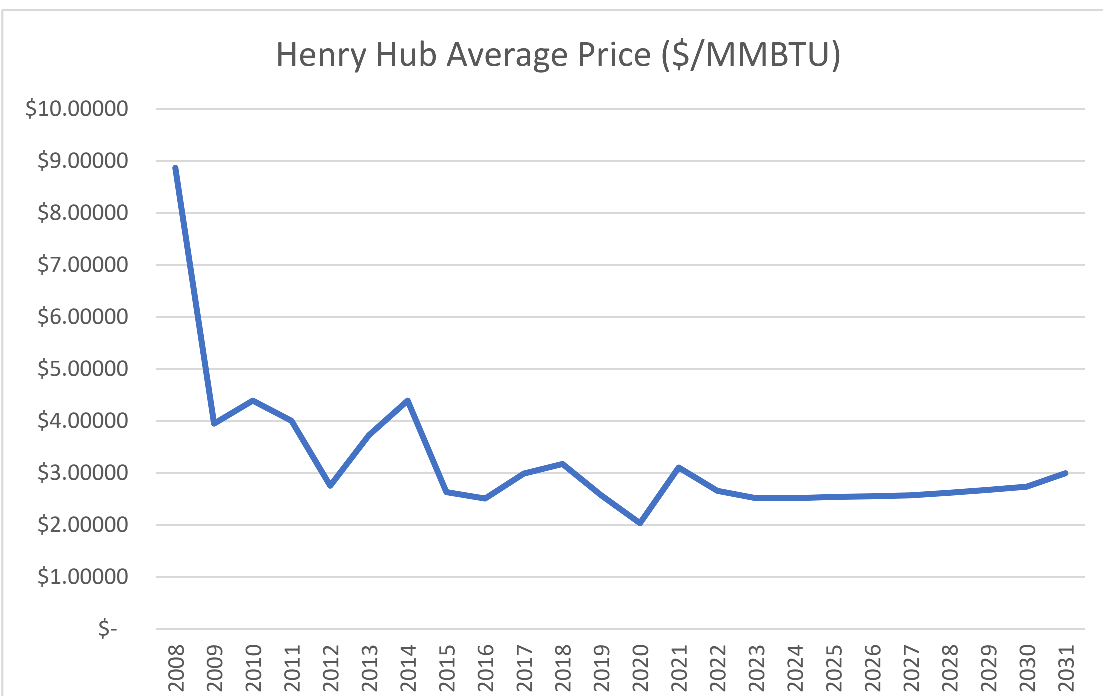
Figure 2: Natural Gas Delivery System



AGL contracts for capacity on interstate pipelines on behalf of the end-use customers in Georgia. AGL receives gas supply from interstate pipelines, storage facilities or its own LNG facilities and distributes the gas to residential, commercial, and industrial customers throughout the state of Georgia. The gas is delivered to customers through a system of high-pressure transmission pipelines and high/medium/standard-pressure distribution mains. A typical residential service is delivered at less than 1 pounds per square inch ("psi"). AGL operates its complex delivery system to meet customers' needs in a safe, reliable, affordable, and clean manner. AGL also establishes sound and effective long-range plans to add and maintain firm gas supply resources to ensure the ongoing successful delivery of natural gas to customers.

Fortunately, natural gas customers have enjoyed the benefit of low natural gas prices for several years and may experience continued low prices for the foreseeable future (see Figure 3 below). The United States has been the world's top producer of natural gas since 2009. Natural gas commodity prices remain relatively low because of the abundance of supply, including natural gas from shale resources, in addition to continued natural gas supply from more traditional onshore and offshore sources within the nation.

Figure 3: Annual Average Prices



Source: S&P Global Market Intelligence (reflects historical prices through February 2021, and projected prices starting March 2021)

CHAPTER 3. NATURAL GAS DEMAND AND FORECAST

3.1. Overview

AGL's Plan includes and relies upon projections of the Company's forecasted firm design day load requirements. The forecasted design day load is used to ensure the Company has secured appropriate levels of capacity to deliver firm gas supply resources to meet AGL's firm customers' needs. The ten-year projected design day load requirement is included in Trade Secret Attachment B.

AGL's system is divided into nine discrete geographic pools or areas across the state. The construct has been a part of the AGL retail choice program since its inception. In its simplest sense, the pools are defined by the firm delivery entitlements of AGL's firm capacity on the interstate pipelines. Most of these nine pools or areas have a level firm demand and a corresponding amount of firm gas supply capability to satisfy the requirements on a standalone basis. A few of the pools have a very limited amount of interplay between them, allowing a pool to share firm gas supply capability or capacity with another pool. The development of a gas supply portfolio having the right amount of gas supply capability or capacity in aggregate while also balancing the discrete needs of the individual pools is essential. No two pools are exactly alike and the mix of customers in each makes their firm demand characteristics dynamic over time. As an example, the gas supply capability for the Valdosta area of the system cannot support meeting load in the largest load center, the Atlanta pool, because the pipelines that serve Valdosta do not run through Atlanta. However, Augusta and Savannah gas supply capabilities may help support the Atlanta pool on a day because the gas in the delivering interstate pipeline "flows by" Atlanta on its way to these two East Georgia pools. These discrete and interrelated pool dynamic details are fundamental to the development of a comprehensive gas supply plan for the AGL system.

On April 1, 2020, an update to the geographic boundaries of several pool groups took effect. Since the last major pool boundary modifications were made in 2005, distribution system improvements have interconnected more areas of the system. The updated boundaries better reflect today's distribution system. The update moved portions of the Rome, Ex-Atlanta SNG, and Ex-Atlanta Transco pool groups into the Atlanta pool group. A small portion of the Atlanta pool was also moved into the Macon pool group. After the pool groups boundaries were modified, new pool group totals for monthly historical billing units and daily historical loads were calculated and a new design day forecast was generated. Due to the adjustment, the i-CDP design day forecast contains a noticeable step-change for those modified pools starting in the 2022-2023 design day.

3.2. Forecast Assumptions and Methods

Demand Forecasting Methodology:

Business Forecast System, Inc.'s regression analysis tool, Forecast Pro XE version 6.0, was used to produce a set of equations that describe firm customer usage in relationship to outside temperature. Historical daily heating degree days ("HDDs"), wind speed, usage per billing unit, holiday, day of week flags or variables, the 7-day rolling average temperature, a year trend variable, an indicator for the winter in which the datapoint falls, and the bend point data or a point along a span of HDD values where firm customer consumption changes were entered into Forecast Pro.

Historical billing units, daily firm usage, and HDDs were gathered separately for each pool. For each day, a use per billing unit was calculated. A use per billing unit is calculated by dividing the day's firm usage of natural gas by the billing units on the system for that month. This calculation is done across each of the nine geographic pools. For each day, bend points at 5 HDD increments (10, 15, 20, 25, 30, 35, and 40 HDDs) were then calculated. Bend points act as spline points in a linear regression. The input bend points for a historical day can be calculated by subtracting the bend point variable from the day's historical HDDs. For example, on a day where there were 16 HDDs, the Bend 10 input variable for that day would be 6 (16 HDDs minus 10). The Bend 15 variable for that day would be 1 (16 HDDs minus 15). All other bend point variables would be set to zero as their resulting calculation would result in a negative value. The bend point helps to capture potential changes in customer consumption behavior as temperatures get colder and resultant HDD levels increase.

Design Day Forecast:

For most pools, the typical dataset used for the design day forecasting includes the core winter months (December - February) for the most recent 5-year period. The results of this baseline analysis are always evaluated for proper fit and trending to ensure that they are relevant and effective at projecting the possible level of gas consumption by firm customers under certain design weather conditions.

Another key component to the forecast is a projection of billing units. As described above, the use per billing unit value is calculated from the historical observations and is used in the regressions. Therefore, the design day forecast requires a forecast of billing units coupled with the pool's design temperature criteria which correlates to an HDD value. With those basic building blocks, the coefficients of the regression analysis can be used to calculate a forecasted design day.

The next component of AGL's design day load forecast is a load value for expected new from large firm commercial or industrial customers. This information is developed by AGL's sales and marketing group. The new large load component attempts to capture new firm loads adding to the AGL system that would not be adequately reflected in the analysis driven solely off of historical load relative to historical billing units and daily weather observations.

This identified new load is compiled for each geographic pool and added to the pool's regression results to produce a base design day load forecast. The projected load on a design day captures shifts in use per billing unit in the historical period, the forecasting of the billing units themselves incorporates attrition and customer growth in general terms. The addition of a large future load component allows the Company to design its supply portfolio to accommodate the future firm customers whose needs are a larger increment than an average customer.

CHAPTER 4. CAPACITY SUPPLY PLAN

4.1. i-CDP's Influence on and Possible Effects to AGL's CSP

This initial filing of the Company's i-CDP has no influence or possible effects to AGL's filed and approved 2019-2022 CSP. The CSP is a statutory requirement, and the i-CDP is not looked at as a vehicle to implement changes to those requirements. The Commission has already approved the Company's CSP covering the period of 2019-2022 in Docket No. 42317. The heating season of 2019-2020 has already occurred, and the 2020-2021 winter period is nearing its conclusion. This i-CDP filing does not seek to introduce changes to the Commission's approval for the criteria used for the final CSP heating season of 2021-2022.

The LNG expansion project that was discussed in the Company's latest CSP is part of a longer timeline perspective, beyond the 3-year period for which the 2019 CSP filing sought approval. The LNG expansion project or any approval of it was not explicitly considered in the Commission's approval of the 2019-2022 CSP. As mentioned above, having the long-term planning horizon is absolutely critical for meaningful gas supply projects. If the Company had to express the need for the added gas supply capability in a 3-year window of a CSP and was looking to take service from those improvements or capacity expansion projects all in that same 3-year window, it would be impractical, if not impossible, given the realities of today's current build times. The construct of the i-CDP filing allows the Company to express the longer-term needs of the overall system. The filing provides the venue to mesh those longer-term needs with those explicitly filed, documented, and approved in a CSP. The essential longer-term perspective of capacity planning and contracting for, or construction of, gas supply projects assures the timeliness of gas supply resources being available.

The process of ensuring that true benefits of longer-term capacity planning decisions and the framework around how decisions are made has always been done by the Company. The i-CDP provides an appropriate venue to share that road map of capacity needs, available market-based or Company-built options, their general availability, and possible timelines. The CSP construct does not provide a venue for sharing this informational long-lead perspective. The i-CDP will provide the Commission with greater details of the Company's long-term resource planning process that will then be further supported in the subsequent CSP. From that perspective, the two regulatory filings will prove to be very complimentary and beneficial.

4.2. Summary

The Georgia Code, O.C.G.A. § 46-4-155, 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 electing distribution company to meet such requirements;

(C) Describe the criteria of the electing distribution company 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 electing distribution company in order to implement such plan; and

(D) Specify the portion of the interstate capacity assets which must be retained and utilized by the electing distribution company to manage and operate its system.

In addition, Commission Rule 515-7-11-.04 specifies the MFRs that must be filed with a proposed CSP.

The CSP establishes the appropriate level of firm gas supply services that the Company contracts for on the Federal Energy Regulatory Commission ("FERC") regulated interstate pipelines as well as on-system gas supply capabilities, which combined serve the utility's firm sales customers in the state of Georgia. Firm gas supply services are made up of Firm Transportation ("FT") capacity on the interstate pipelines and out of state storage services. These pipelines are Southern Natural Gas Pipeline ("SNG") and Transcontinental Gas Pipe Line Company ("Transco"). For purposes of the filing, the Company is relying on the recently approved 2019 CSP (Docket No. 42317), which included the approved array of interstate capacity assets for the heating seasons of 2019-2020, 2020-2021, and 2021-2022. The array of interstate assets from the 2019 CSP is included in Trade Secret Attachment C.

As fully explained in the approved 2019 CSP, the Company determines its annual design day supply requirements based on its forecasted design day load requirements. After considering other resources (e.g., LNG and Bundled Peaking Service) that will help meet the total design day supply requirements, the Company determines the "range of requirements" that must be met with interstate capacity assets. The Company has provided ten-year projections of its design day supply requirements in Trade Secret Attachment B. The Range of Requirements is provided in Trade Secret Attachment D.

4.3. Liquefied Natural Gas ("LNG") Expansion

On-system peaking assets provide a cost-effective resource to reduce the amount of firm gas supply capacity that the Company needs to secure on the interstate pipelines. It is important to note that the three Company-owned LNG facilities are integral to the gas supply capability of the AGL system. If any one or more of these plants were to fail, the supplemental delivery of a comparable amount of natural gas by either SNG or Transco would not be physically possible without significant time and expense.

Today, AGL has access to a meaningful amount of on-system LNG resources. Currently, these LNG facilities can provide up to 940,000 Dth/day of gas to serve firm demand on a Design Day. Because of the current LNG storage tank size, the LNG plants can only provide this peak level of gas supply or sendout for a handful of days. AGL proposes to increase the capability of its LNG assets to address not only the increasing firm design day load requirements, but also to meet near-term customer needs in a durationally cold winter. The overall need for incremental LNG supply is outlined in Trade Secret Attachment D. That attachment illustrates the projected design day system load growth and how that growth in forecasted firm load can best be met with added LNG capabilities while supplementing with a reasonable amount of bundled peaking. AGL's past CSP filings speak to the need to limit its overall reliance on bundled peaking services in a capacity constrained marketplace.

As discussed in witness Becker's testimony in the 2019 CSP docket:

> "AGL's analysis shows that the need for added supply is over a small number of days and not a long durational need. Therefore, a peaking resource is the better fit to the system's need. Additional pipeline capacity could meet the identified daily need, but would be a poor fit from a durational basis. Additional FT or pipeline capacity would result in a very low load factor, as it would not be utilized very frequently. And, as noted, AGL knows of no new pipeline capacity planned or under construction that could meet projected load growth in such a short timeline. The risk around getting a pipeline project scoped, filed, approved, and then constructed in time for a 2023 or 2024 in-service date is not feasible in the current regulatory

environment. Accordingly, AGL's proposal to enhance its on-system gas supply capabilities through an expansion at the Cherokee LNG site is the best alternative."

Further supporting evidence of AGL's perspective on interstate pipeline project uncertainty was demonstrated in July 2020 with the cancellation of the Atlantic Coast Pipeline project. The regulatory hurdles, resultant cost overruns, and a myriad of other factors ultimately led the project sponsors to cancel the project – after years of seeking approval to construct and operate the first new gas supply resource into the mid-Atlantic region in decades. Mountain Valley pipeline project is facing similar headwinds today. PennEast Pipeline project continues to face regulatory challenges and delays before the FERC. None of these natural gas pipeline projects would have provided incremental gas supply capability directly to the Georgia market; however, these very important market events have served to shape the perspective of any future infrastructure projects. Additionally, with the changing of the presidential administration, an executive order was put forth that halted the progress on the long-awaited Keystone XL pipeline. These various projects were all in various stages of review, approval or design when delays were introduced. In the case of Keystone XL pipeline, a crude oil pipeline, the project was first proposed in July 2008 – more than 12 years ago. While this is a crude oil pipeline, the regulatory review, permitting, and authorization process is very similar to that of a natural gas pipeline.

As another example, in February 2021, FERC solicited feedback from stakeholders on a project that had been reviewed and approved in a 2016 docket. They were accepting feedback on whether or not the FERC should revisit its authorization of a project that had been approved more than 4 years ago. They were seeking input on a compressor station's operations that was a part of the approved project and had already been placed into service. As Administrations change, long-range plans that had been approved can be suddenly derailed by new policy views. It seems unlikely that some polarized issues will be stabilized in the near future. The environment will be challenging for AGL and other utilities to properly plan and successfully serve growing customer bases. Given the long lead-times required to get a project approved and constructed, project interruptions could force utilities to implement stopgap solutions which may be less optimal, less reliable, and/or potentially more expensive for the customer.

AGL does not have a stake in any of these projects for incremental firm capacity. If it did, and incremental pipeline capacity were its only option, AGL would be facing stifled customer growth, a shrinking customer base, and lost economic growth opportunities. On the contrary, through years of pro-active capacity management the Company continues to forecast year-over-year growth, resulting in a need for incremental gas supply capabilities. Taking the long view has afforded the Company this unique opportunity. By enhancing the system's LNG capabilities, AGL can support economic growth in the State of Georgia by creating the needed gas supply capability in the right location, at the right operating pressure, and have the incremental services available in a timely manner, all while being cost effective in providing safe, reliable natural gas service. And this can be done without the risk of delay or uncertainty associated with project permitting requirements of interstate pipeline capacity projects.

The other aspect to consider in all of this is cost. AGL has determined that the Cherokee LNG expansion project, the details of which are discussed in Chapter 5.7 of the i-CDP, is the best cost alternative to create gas supply capability matching the physical needs of the system. There are a couple of recent projects the Company can use as a comparison. At the time of its cancellation, the Atlantic Coast Pipeline project was engaged with project participants with long-term FT agreements. While the exact information is still being treated as confidential and trade secret, the project costs for a shipper wanting to secure as much as 400,000 Dth/d would have been about $4.3B in firm pipeline reservation fees over the course of a 20-year term commitment. This now cancelled project would not have offered service in the AGL service territory, and AGL did not have any participation in this project. For the shippers who were a part of it, the loss of the first incremental pipeline service from a new interstate pipeline provider to come along in decades was a major loss. In discussions with East Tennessee Gas Pipeline on a potential expansion project, the indicative cost for up to 25,000 Dth/d would have been no lower than $350M over the span of 20 years. Both of these projects would have been far costlier alternatives than the proposed Cherokee LNG expansion.

The planned LNG expansion positions the Company's gas supply resources, on a forecasted design day, to become even more reliant on on-system LNG utilization. The projections show as much as 35% of its forecasted design day firm load requirement will come from LNG supplies in the next 5 years. Looking out 10 years, that figure grows to 41%. This growing reliance on a single source of supply makes it prudent, if not essential, to consider a single contingency failure perspective governing the established reserve margin for the system or at least pool groups that make up the overall system. It is also most appropriate to share that in this 10-year outlook the Company will continue to explore opportunities for incremental interstate transportation-based gas supply resources. Coupled with the necessary shift in reserve margin perspective, the Company needs to evaluate the impact of an LNG failure and infrastructure needs to absorb a meaningfully higher amount of natural gas delivery off of the interstate pipelines if there were to be a service disruption at any one of the three LNG facilities – Riverdale, Macon, and Cherokee LNG plants.

The timeline for the LNG expansion, as currently planned, contains a few key milestones. The first key milestone, which is slated to occur in Q4 2023, is adding a second storage tank at the Cherokee LNG plant. The basic plan would be to continue with liquefaction of natural gas after the tank is ready for use. The Company is initially planning to have enough LNG to offer 3 or more days of LNG sendout at a rate of 75,000 Dth/d. The incremental LNG sendout would leverage the existing vaporization capacity at the Cherokee plant that is currently earmarked as operational reserve capability. This incremental LNG sendout would be available only because of the added storage capability. Otherwise, the Company would be depleting inventory from the LNG tank at a greater rate; thereby turning the 5 days of inventory into something closer to 4 days. In a durationally cold winter, anything less than 5 days of inventory would not meet expected firm customers' supply needs. The timing of the added storage capacity from a second tank and the possibility of added liquefaction installation will allow AGL to liquefy up to an additional 600,000 Dth before the core of the 2023-2024 winter period begins, which will strengthen the Company's supply position should the winter be cold and extended.

The next milestone in the project timeline is to replace the current liquefaction train. As is discussed in greater detail later in the filing, the current liquefaction equipment at the Cherokee LNG plant has been in service beyond its useful life and needs to be replaced. It is currently rated to create up to 10,000 Dth/d of LNG. Since the plan is to double the storage capability of the plant, the liquefaction capability will also be doubled to 20,000 Dth/d. This will allow the Company to fully fill the LNG tanks during the summer refill season of 2024 and have up to 4.1 Bcf of LNG available for the 2024-25 heating season. The added LNG inventory would safely allow AGL to use all of the plant's existing vaporization capacity; 26,000 MSCFH or 520,000 Dth/d without degrading the durational availability of the peaking resource.

After the heating season of 2024-25, the added vaporization capability at the plant would be in place. For the heating season of 2025-26 and beyond the Company can begin to use an incremental 400,000 Dth/d of sendout capacity from the expanded Cherokee LNG facility. As the schedules show, LNG utilization is projected to grow over time as firm load is forecasted to increase. Any time after the summer of 2028 and the planned installation of the Cumming to McGinnis Ferry system reinforcement, the full 800,000 Dth/d of LNG sendout capability could be physically moved into the AGL system for consumption by firm customers on a design day. Until that time, the physical sendout capability of the plant will be 42,000 MCFH but the pipeline system would limit that sendout to 37,000 MCFH for a daily total of 740,000 Dth/d. AGL's projected reliance on the Cherokee LNG facility stays below both these limits during the planning horizon.

The overall utilization of the expanded Cherokee LNG facility is illustrated in Figures 4, 5, and 6. The Cold Winter Load profiles shown in each figure were calculated by using actual weather from the heating season of 2009-2010, a recent winter containing sustained cold periods. These historic daily HDD levels were used in conjunction with the most recent regression analytics and its resultant load coefficients along with AGL's current billing unit forecast figures for the Atlanta Pool. A design day event is superimposed on that resulting load profile as a typical 3-day event – cold days on the front and back end of a design day.

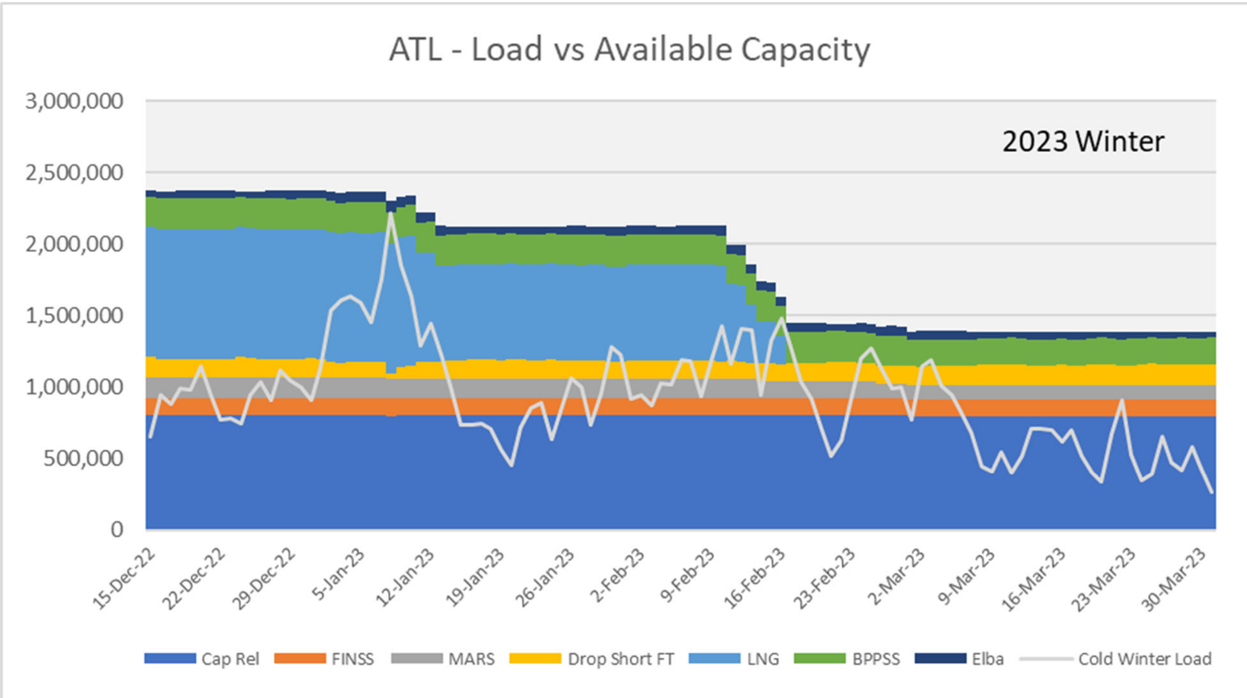
Capacity Release includes all the gas supply resources that the company releases to the Certificated Marketers to use in meeting firm customer load. FINSS and MARS are tariff-based sales services made up of additional gas supply resources contracted for on the interstate pipelines. Drop Short FT is an operational flexibility that exists in the Atlanta pool based on its geographic location. Firm Transportation capacity that has delivery entitlements on the east end of the AGL system in Augusta and Savannah is pathed on the interstate pipelines along a route that passes by the Atlanta area. If a portion of that firm entitlement is not needed to meet design day load in those furthest pools, the FT capacity can be used to "drop" gas off at the Atlanta pool on a design day.

LNG peaking service is made up of on-system LNG resources (Cherokee and Riverdale along with a portion of the Macon facility). BPPSS is comprised of interstate pipeline based peaking supplies. All of the assets in these two categories are very short durational supplies – available for 5 days or less in most cases. As the AGL CSP indicates, there is a planned bundled peaking or city-gate delivered gas supply component included in the BPPSS service.

In the figures below, once a storage resource hits a ratchet, its deliverability is reduced in subsequent days. Once a storage or LNG asset has depleted its inventory, its deliverability is reduced to zero in subsequent days on the chart.

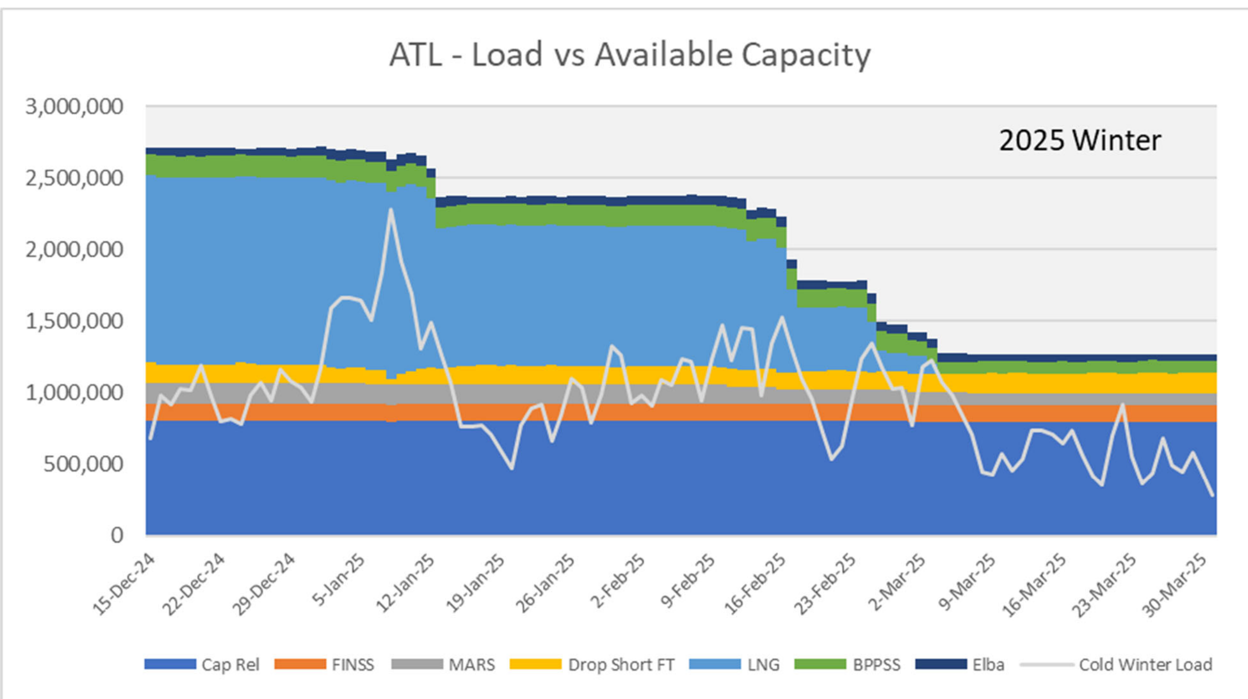
For the projected winter of 2022-2023, AGL anticipates being able to satify the forecasted firm demand in the Atlanta Pool, as shown in Figure 4 below.

Figure 4: Load versus Available Capacity 2022-2023 Winter



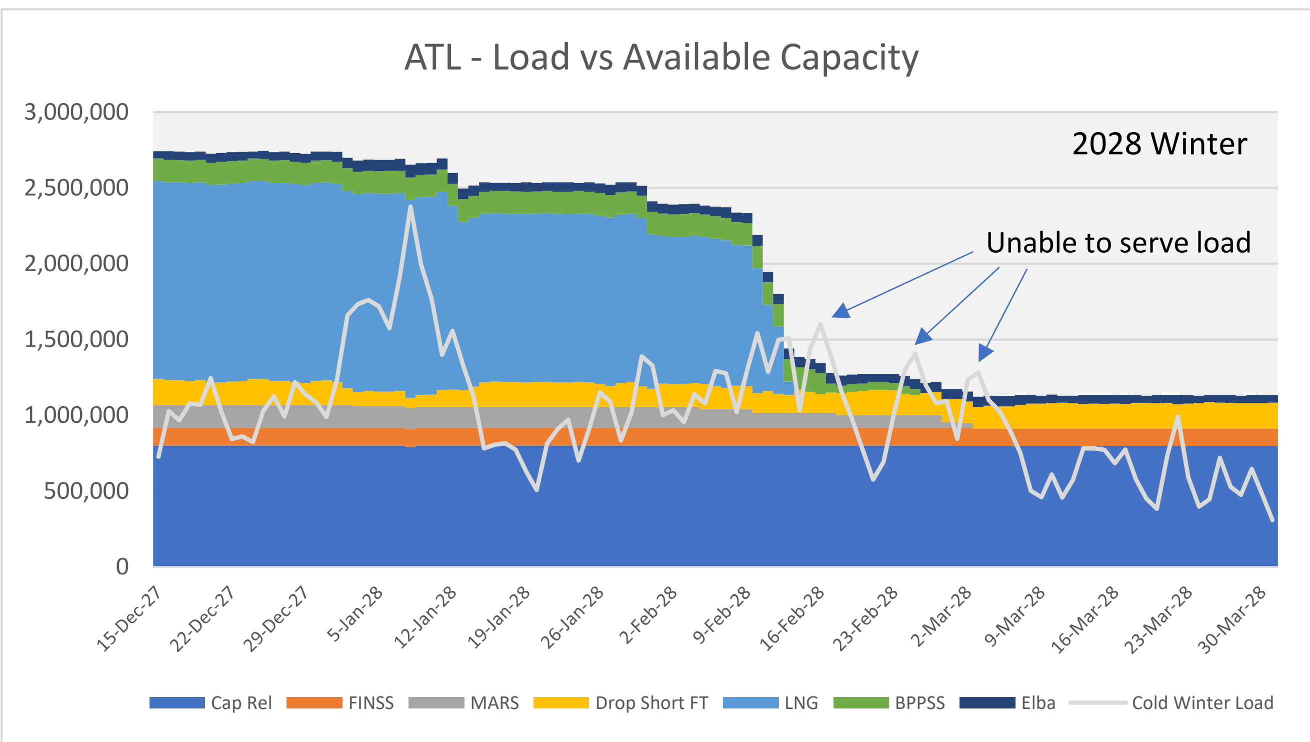
As shown in Figure 5 below, the Company is projecting out to the heating season of 2024-25, AGL uses the same forecasting approach to calculate firm load. By this time, the Cherokee LNG facility will have full access to all its existing 520,000 Dth/day of vaporization capability. This is available to the system because the liquefaction capability of the plant is projected to be doubled in the previous year. Without the added liquefaction capability, the added sendout capability would only serve to effectively shorten the durational availability of natural gas from the LNG Plant from about 5 days to around 3 days. In order for the projected load to be satisfied, the LNG plant would need to run at nearly 100% of its equipment's rated capacity. While that is certainly an acceptable plan, it does not come without risks. Failure of any one component of the vaporization process could meaningfully reduce the amount of gas supply available from the plant. Additional gas supply capability of that magnitude would be nearly impossible to replace or replicate with additive supply being delivered from the interstate pipeline system. Because of this great risk, the Company plans to re-evaluate the reserve margin needs of the geographic pool groups as well as the system as a whole.

Figure 5: Load versus Available Capacity 2024-2025 Winter



As shown in Figure 6 below, looking out to the heating season of 2027-28 using the same techniques to project firm load as developed in the earlier examples, a further challenge presents itself. The firm load expectations will exceed the durational capabilities of the upgraded LNG facility. There are several ways to approach this projected shortfall. The heart of it is to introduce further durational gas supply capabilities to the AGL system. One simple alternative would be to eliminate the restrictive provisions around the FT capacity that AGL contracts for with firm receipts at Elba Island. Additional reductions of the limits placed on the Transco capacity originating at Station 210 may also help. Currently the utility is only allowed to call on FT capacity with receipt at Elba Island for 5 days in any heating season. Making that gas supply available, like any other FT on the system, would help reduce the number of days that peaking supplies, like Cherokee LNG, would need to be partially or fully utilized. Further, the utility will begin searching for additive firm transportation capability to augment the gas supply capabilities of the system. This set of circumstances was also mentioned in the Company's 2019-2022 CSP.

Figure 6: Load versus Available Capacity 2027-2028 Winter



CHAPTER 5. INFRASTRUCTURE DELIVERY PLAN

5.1. Key Challenges, Programs, and Long-Term System Needs

There are multiple challenges facing AGL as it strives to maintain safe and reliable service to its customers while supporting growth, implementing industry best practices, replacing aging facilities, complying with current and new regulatory requirements, and increasing environmental stewardship measures; all while striving to keep customer costs as low as possible. These challenges include, but are not limited to, the following:

- Significant growth in residential, commercial, and industrial usage of natural gas over the past decade continues to require large investments in peaking and infrastructure.
- This continued projected growth, coupled with limited interstate pipeline capacities, has required AGL to find alternatives to meet customer demands on the coldest days of the year, such as the Cherokee LNG facility expansion detailed in sections 4.3 and 5.7 of this document.
- Supporting this growth also requires moving the gas from the supply pipelines and facilities to the customers. This has been a challenge that was previously met under the Commission approved i-SRP (STRIDE) program. Although that rider program ended multiple years ago, the growth and associated need for these types of projects continued. The system continues to have constrained areas that are unable to provide adequate supply to customers on a design day without the deployment of mobile LNG vaporizer units.
- Replacing aging facilities continues to be a focus of the Company as AGL strives to maintain a safe and reliable system and to reduce methane emissions from these older facilities. This work has also previously been completed under separate rider programs for bare steel and cast-iron replacements as well as replacements of early vintage plastics. While the foresight and support of the Commission for these programs has kept AGL as a leader within the industry in replacing these higher-risk facilities, the need for large scale infrastructure replacement programs continues.
- New regulatory requirements continue to require significant infrastructure investments—the largest of which is the PHMSA rule released in October 2019 requiring Operators to reconfirm the MAOP of their transmission pipelines. This requirement has an estimated total cost for AGL exceeding $700 million over a 15-year period. While the new rule allows for the work to be completed over a 15-year period, this still equates to an additional

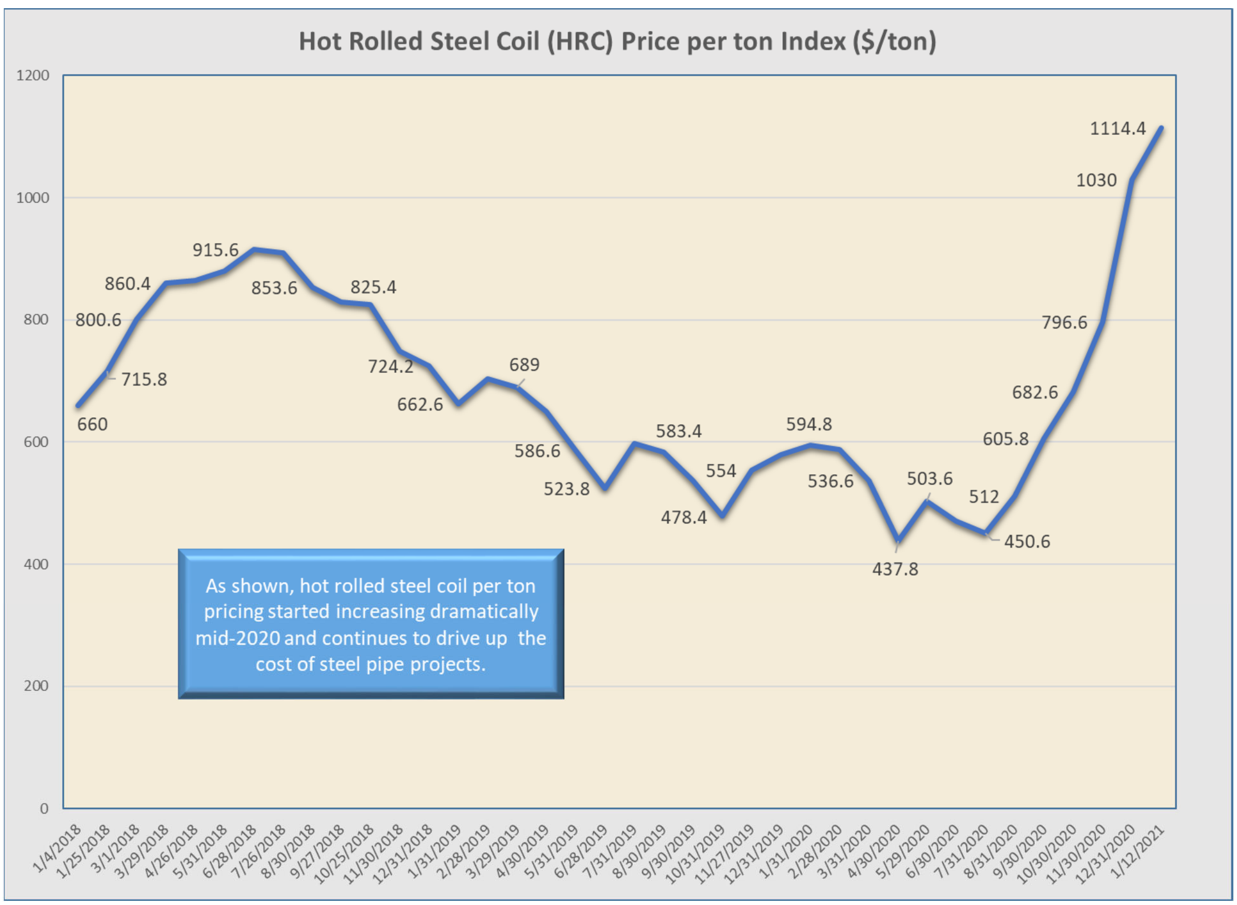
mandated infrastructure capital investment of nearly $50 million each year in this 10-year forecast.

- Along with the known requirements, there are multiple currently proposed requirements that have not been fully provided for in this plan because the final requirements and timing are not yet known. These proposed new requirements include but are not limited to:
    - PHMSA Valve Installation and Minimum Rupture Detection Standards (Docket No. PHMSA-2013-0255) – This proposed rule will likely require remote-controlled valve ("RCVs") or automatic shut-off valve ("ASV") installations on all new and partially replaced transmission lines. The proposed rule also addresses rupture detection and response standards that have the potential to involve existing transmission pipelines as well. The potential for inclusion of existing transmission line valves has significantly increased with the provisions specific to existing valves within the recently signed PIPES Act of 2020 as further outlined within this section. Although the final regulatory mandates are not yet known with certainty, installing RCVs on major segments has emerged as an acknowledged best practice. Thus, AGL is beginning to ramp up its investments around installation of RCVs on some of its highest-risk transmission pipelines, but the Company acknowledges that the final wording of this rule has the potential to require significant acceleration of these investments.
    - GA PSC Docket No. 43465 – Notice of Proposed Rulemaking ("NOPR") – Consideration of Rules Addressing the Safe Installation and Operation of Natural Gas Transmission and Distribution Systems – This ongoing NOPR includes potentially significant new requirements in multiple areas including reporting, requirements around leaks, Abandonment of Inactive Service Lines, Valves, System Records and Maps, Uprating, and Personal and Respiratory Protection Equipment. While the actual impacts of these new requirements cannot be determined until a final rule is published, many of these proposed items as initially issued as a proposed rule could require significantly higher investment in these areas to achieve compliance.
    - Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 ("PIPES Act of 2020") – This new law was signed by the President on December 27, 2020 and includes the necessary reauthorizations for PHMSA but also includes multiple requirements to PHMSA to propose new rulemakings related to the Merrimack Valley incident in 2018. The PIPES Act of 2020 includes an array of

Congressional mandates to PHMSA including Distribution Integrity Management Program ("DIMP") and emergency response plan enhancements, implementation of Pipeline Safety Management Systems ("PSMS"), requirements around idled pipe, new regulator station requirements, RCV requirements for transmission lines as noted above, and multiple mandates around reducing methane releases.

- Changes in key material prices can have a significant impact on project costs. In the current environment, it is very difficult to predict changes in commodity prices within a 10-year or even a 3-year period. A current example is the significant increase in the cost of rolled steel which is the base for steel pipe. As shown below, hot rolled steel coil prices have increased from a low of approximately $438 per ton in April 2020 to approximately $1,114 per ton in January 2021. This more than doubling of the cost of steel within a 9-month period is significantly affecting steel pipe costs which in turn significantly increases the costs for many of AGL's larger pipeline projects.

Figure 7: Price of Hot Rolled Steel Coil (HRC)



- Tight Labor Markets – There is a shortage of general and craft labor, which puts upward pressure on costs. These work levels continue to strain the current market for craft labor requiring additional salary and retention investments by pipeline contractors which in turn increase project costs.
- Implementation of Best Practices – AGL continually reviews and implements best practices across its system to increase safety, reliability, and customer service. While many of these best practices require additional infrastructure investment, the corresponding risk reductions and increases in safety and customer service have been deemed by the Company to be worthy investments. Current examples include:
    - Programs to reduce the likelihood of an over pressurization event based off of best practices identified in the wake of the Merrimack Valley incident including:
        - The "Partition Valve" program as outlined in section 5.15 of this document which is designed to mitigate existing single valve separation points between two different pressure systems
        - Multiple regulator station safety enhancement programs as outlined in section 5.16 of this document
    - Strengthening and formalizing the creation of "Flow Interruption Plans" to increase safety when tying into, relocating, retiring, or otherwise physically changing the flow of gas in the system
- Environmental Stewardship Measures – AGL continues to look for innovative ways to reduce its environmental footprint. In addition to the opportunities identified in section 8 of this document, other operational efforts are being tested and implemented. One example is the testing of portable gas compression options where possible to reduce the impacts of gas releases during blowdown activities.

Each of the challenges, programs, and best practice implementations listed above, as well as basic financial factors such as inflation, have the potential to significantly affect the current i-CDP.

5.2. Summary of Proposed Projects and Action Plans

As outlined in the "Pre-Filed Direct Testimony of Steve Murphy, Jennifer Rose, Donald Carter, and Bradley J Beckman on Behalf of Atlanta Gas Light Company" in the 2019 rate case filing, also known as the "Engineering Panel" testimony, AGL proposed multiple projects and programs to help ensure a safe and reliable system while supporting the continued growth and minimizing where possible the impacts to customer rates. The Engineering Panel testimony included fifteen safety programs plus support for customer growth and other required work.

The safety programs are as follows:

1. Reconfirming MAOP - Verifying whether AGL can continue to operate its transmission pipelines at their current MAOPs. PHMSA mandated program began July 2020 and ends July 2035.
2. Modifying Pipelines for Smart Pigs - Modifying AGL's transmission pipelines to allow internal inspection tools, commonly known as "smart pigs," to collect pipeline integrity data and to identify parts of pipelines that pose risks. This work will continue on selected pipelines that have been identified as candidates for retrofit but no ending date has been identified for this initiative.
3. Preventing Alternating Current ("A/C") Hazards - Installing protective systems on existing transmission pipelines to prevent accelerated corrosion.
4. Installing Remote-Controlled Valves ("RCVs") - Expanding the use of RCVs on AGL's existing transmission pipelines to enable faster responses to unsafe conditions. AGL has not determined a timeline for this work since there are many unknowns as to what the PHMSA Notice of Proposed Rulemaking will require as well as what guidance will be provided by the PIPES Act. It should be noted that new and fully replaced transmission pipelines include strategically placed valves that include remote controls or remote-control capabilities.
5. Replacing Higher Risk Pipelines - Prioritizing system replacement based on DIMP risk analyses. There is no end date for the DIMP requirements.
6. Remediating POSI-HOLD Couplings - Replacing or repairing POSI-HOLD couplings near end caps on systems operating at elevated pressures. AGL is in year 4 of 5, with a program completion commitment of 7/1/2022.
7. Remediating Cased Crossings - Verifying electrical isolation of pipelines at cased crossings and remediating any identified isolation failures. The GPSC casing program began July 2018 and will end July 2025.
8. Evaluating Regulator Stations - Reviewing existing regulator station designs and making necessary changes to stations to help prevent over pressurization of AGL's system. This program, called Regulator Station Review Program (RSRP), is scheduled to be completed in 2023.

9. Retiring Inactive Services - Reducing the risk of excavation damage to inactive service pipelines that have little or no potential for providing service. AGL is currently addressing the highest risks, such as instances where a structure is going to be demolished. Other abandonments often occur in conjunction with main retirements or replacements performed in the same general area so as to take advantage of cost savings associated with mobilizing field resources on a project. This initiative may be affected by the GPSC NOPR in Docket No. 43465. Once the NOPR is finalized, the Company will re-evaluate its approach to retiring inactive services.

The following programs have significant O&M impact, which will be addressed in the Annual GRAM Filing:

1. Replacing Celcon Caps on Service Tees - Identifying and replacing Celcon caps on higher risk service tees installed between 1984 and 1995 to avoid leaks and potential service disruptions.
2. Inspecting Sewer Systems for Potential Cross-bores - Identifying natural gas pipelines within sewer systems using a robotic camera and relocating AGL's pipe to eliminate unintended damage during sewer clearing.
3. Reducing Third Party Excavation Damages - Implementing a watch and protect program focused on AGL's critical pipelines.
4. Improving Data Quality and Accessibility - Converting older paper pipeline records into electronic formats, validating the records, and making those records readily available to field personnel.
5. Expanding Quality Assurance - Enhancing existing quality assurance evaluations at AGL to include operations and maintenance work.
6. Applying PSMS - Implementing a Pipeline Safety Management Systems ("PSMS") at AGL.

Along with the safety and reliability programs listed above, the Engineering Panel also included additional programs to address growth and other required work. These programs included:

- System Reliability Projects – These are generally large-scale new pipelines to get the gas supplies from the supply points to the areas of the state where there is the most growth. Going forward, these projects will be considered, and Commission-approved projects will be funded by the SRR charge as a ratemaking process within each i-CDP.

- LNG Facility Upgrades – AGL relies heavily on three LNG plants strategically located across the state to provide peak gas on the coldest days of the year. These plants all have significant age and require some large capital improvements to maintain reliability and operability when called upon. This is an ongoing initiative,[7] nonetheless, AGL is accelerating investments in this area for a few years to address some key issues as outlined in section 5.6.
- DOT Relocation Work[8] – AGL is required to relocate Company facilities located in road rights-of-way when the state, county, or municipal entity makes significant changes to their roadways (e.g., road widenings, intersection improvements, etc.). This is an ongoing requirement.
- New Business – This is ongoing work, required by the Tariff, to serve new customers and to accommodate changes in loads for existing customers.
- Economic Development Projects – Projects specifically designed to provide natural gas access to unserved and underserved areas of the state, support economic growth, and serve large-scale developments and industries. This ongoing work is generally done through the Universal Service Fund (USF) program or the Econ-1 program with all projects approved by the Commission within the framework of those rules.

In addition to the programs and initiatives outlined above, AGL must continue making investments to support and maintain its system and daily operations. This includes, but is not limited to, vehicle and equipment purchases (Fleet), building maintenance, repairs, and replacements necessary to support operations (Facilities), and expenses and investments necessary to control corrosion of the Company's steel pipelines (Corrosion).

Finally, as outlined in the 2019 CSP and in section 4.3 of this document, it is necessary to expand the Cherokee LNG facility to provide adequate gas supplies on the coldest days of the year. Sections 5 and 6 of these documents include supporting details for each of these programs.

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[7] The need to maintain and replace LNG equipment as the equipment the end of its expected useful life is incremental to, and independent of, the proposed new LNG tank and related facilities to expand the Cherokee LNG plant capabilities discussed in section 4.3 of this Plan.

[8] The term "DOT Relocation" is used generically to refer to relocations of the Company's facilities in public right-of-ways, and is inclusive of the relocations performed because of public work done by or on behalf of any local, state or federal authority.

5.3. Proposed Three-Year Budget

The proposed three-year capital budget for AGL is shown below and includes the investment needed to address the items outlined within Chapter 5 of this document. The significant increase in investment is mostly attributable to the Cherokee LNG supply expansion as outlined in sections 4.3 and 5.7 of these documents.

Table 4: Proposed Three-Year Budget

AGL Capital Budget ($ millions) (Includes OH, AFUDC, and estimated IT Allocations)	2022	2023	2024
	513.0	595.6	604.1

5.4. Proposed Ten-Year Budget

The proposed ten-year capital budget for AGL is shown below and includes investment needed to address the items outlined within Chapter 5 of the document:

Table 5: Proposed Ten-Year Budget

AGL Capital Budget ($ millions) (Includes OH, AFUDC, and estimated IT Allocations)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	513.0	595.6	604.1	554.5	521.7	527.6	533.4	539.2	545.4	550.8

Table 6: Bill Impacts[9]

AGL - Bill Impacts ($ millions)	2022	2023	2024	
Annual Revenue Deficiency	61	54	49	
Annual Impact	30.27	26.60	23.96	
Monthly Impact	2.52	2.22	2.00	
				3yr Average
Non-Gas Impact	7.4%	6.0%	5.1%	6.2%
Total Bill Impact-Includes Est Gas Costs	3.7%	3.1%	2.7%	3.2%

A breakdown by budget line item and specific program is included below and as a part of the table below.

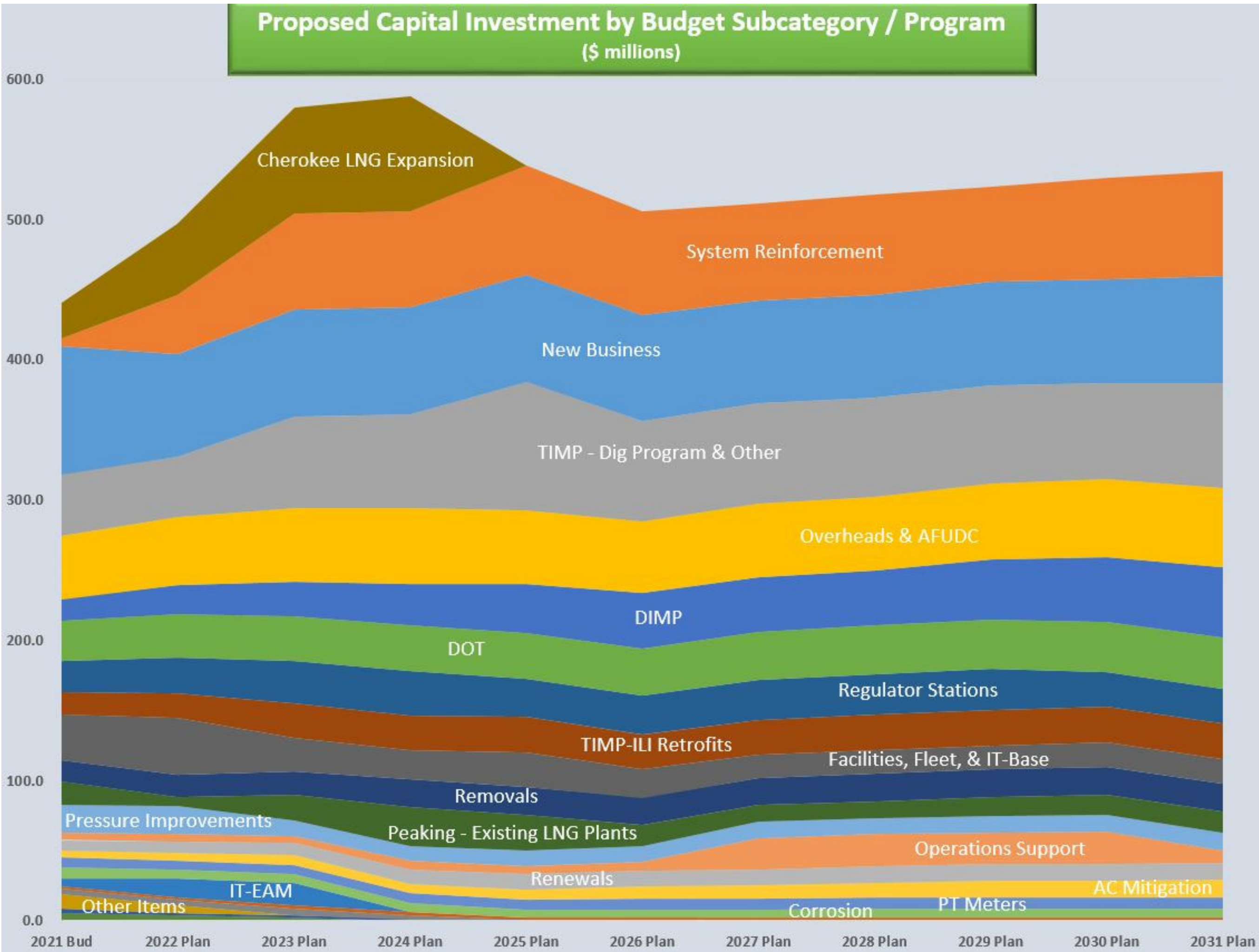
[9] The estimated revenue requirements and rate impacts provided in the table are based on numerous estimates and assumptions. These assumptions include capital spend and estimated cost, asset in service dates, growth in customers and revenues and growth in expenses based on inflationary factors applicable to the specific cost. Additionally, the estimates assume the current federal and state income tax rates and applicable tax rules and regulations. When AGL files its annual GRAM filing for 2022-2024, the actual results will likely differ from the estimates provided in the table.

The estimated revenue requirements and rate impacts includes capital spending and estimated in service dates for projects that are eligible for recovery under the SRR. The estimates do not include the capital spend associated with the Cherokee LNG expansion. This expansion is expected to be placed in service in January 2025 and will result in an additional revenue requirement of approximately $27 million and monthly average residential customer rate increase of approximately $1.11.

Table 7: AGLC Capital Budget

AGLC - 2021 Budget 2022-2031 Plan (in $MM)	Regulatory Groupings	2021 GRAM (7/1/20)	2021 Budget (1/1/21)	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
Total Capital Budget - All Programs (incl. OH & AFUDC)		**434**	**440.2**	**497**	**579.6**	**588.1**	**538.5**	**505.7**	**511.6**	**517.4**	**523.2**	**529.4**	**534.8**
Estimated IT Allocations (Budgeted under AGSC)		16	16	16	16	16	16	16	16	16	16	16	16
Total Estimated Capital Expenditure		450	456.2	513	595.6	604.1	554.5	521.7	527.6	533.4	539.2	545.4	550.8
Budget Category 1: GRAM - Safety & Compliance (GRAM-S&C)		**137.5**	**130.7**	**133.3**	**164.3**	**168.9**	**197.5**	**185.2**	**185.1**	**186.8**	**191.6**	**193.3**	**204.7**
Distribution Integrity Management Program (DIMP)		**16.1**	**15.8**	**20.6**	**24.9**	**30**	**35**	**39.9**	**39.6**	**38.9**	**42.4**	**45.7**	**50.2**
DIMP	*GRAM-S&C*	*16.1*	*15.8*	*20.6*	*24.9*	*30*	*35*	*39.9*	*39.6*	*38.9*	*42.4*	*45.7*	*50.2*
Department of Transportation Driven Projects		**27.9**	**28.2**	**30.9**	**31.5**	**32.1**	**32.8**	**33.4**	**34.1**	**34.8**	**35.5**	**36.2**	**36.9**
DOT	*GRAM-S&C*	*27.9*	*28.2*	*30.9*	*31.5*	*32.1*	*32.8*	*33.4*	*34.1*	*34.8*	*35.5*	*36.2*	*36.9*
AC Mitigation Projects		**7**	**5**	**5**	**6.5**	**6.5**	**7**	**9**	**9**	**11**	**12**	**12**	**12**
AC Mitigation	*GRAM-S&C*	*7*	*5*	*5*	*6.5*	*6.5*	*7*	*9*	*9*	*11*	*12*	*12*	*12*
Shorted Casing Remediation Program		**5**	**4**	**4**	**5**	**2.5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Shorted Casings	*GRAM-S&C*	*5*	*4*	*4*	*5*	*2.5*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Transmission Integrity Management Program (TIMP)		**63.9**	**60.0**	**61.3**	**90.0**	**91.8**	**116.9**	**96.9**	**96.4**	**95.9**	**95.4**	**93.0**	**99.1**
Transmission Integrity Mgmt Pgm (TIMP) (General)	*GRAM-S&C*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
TIMP-Dig Program	*GRAM-S&C*	*46.2*	*44.1*	*43.3*	*65*	*66.9*	*91.9*	*71.9*	*71.4*	*70.9*	*70.4*	*68*	*74.1*
TIMP-ILI Retrofits	*GRAM-S&C*	*14.4*	*9.4*	*15*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*	*20*
TIMP-Other	*GRAM-S&C*	*3.3*	*6.5*	*3*	*5*	*5*	*5*	*5*	*5*	*5*	*5*	*5*	*5*
Corrosion Control Projects		**7.6**	**7.7**	**6.5**	**6.4**	**5.9**	**5.8**	**5.9**	**6**	**6.2**	**6.3**	**6.4**	**6.6**
Corrosion Work	*GRAM-S&C*	*7.6*	*7.7*	*6.5*	*6.4*	*5.9*	*5.8*	*5.9*	*6*	*6.2*	*6.3*	*6.4*	*6.6*
System Renewals (GRAM-S&C)		**10**	**10**	**5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
RENEW-Posi-Holds	*GRAM-S&C*	*10*	*10*	*5*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Budget Category 2: GRAM - Other than Safety & Compliance (GRAM-Othe		**247.6**	**268.2**	**261.1**	**271.2**	**268.5**	**262.7**	**246.7**	**257**	**259.2**	**264.2**	**264.3**	**254.7**
NB - Core Work		**69.4**	**68.4**	**72.8**	**76.1**	**76.2**	**75.9**	**75.4**	**73.6**	**72.7**	**73.7**	**74.6**	**76.5**
NB-Core New Business	*GRAM-Other*	*69.4*	*68.4*	*72.8*	*76.1*	*76.2*	*75.9*	*75.4*	*73.6*	*72.7*	*73.7*	*74.6*	*76.5*
NB - Large Strategic Efforts		**8.8**	**23**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
NB-USF CNG PSC Funded	*GRAM-Other*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
NB-IP USF Rate Base	*GRAM-Other*	*8.8*	*23*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
NB - Overheads & AFUDC		**7.8**	**9.5**	**5.8**	**5.6**	**5.7**	**6.2**	**6.5**	**6.4**	**6.4**	**6.6**	**6.9**	**7**
NB-NB Overheads & AFUDC	*GRAM-Other*	*7.8*	*9.5*	*5.8*	*5.6*	*5.7*	*6.2*	*6.5*	*6.4*	*6.4*	*6.6*	*6.9*	*7*
Facilities		**22.4**	**18.6**	**28.5**	**14.0**	**9**	**13.5**	**8.3**	**6**	**6.3**	**6.3**	**6.5**	**6.5**
Facilities	*GRAM-Other*	*22.4*	*18.6*	*28.5*	*14.0*	*9*	*13.5*	*8.3*	*6*	*6.3*	*6.3*	*6.5*	*6.5*
Fleet		**11.4**	**12.1**	**8.6**	**8.2**	**8.4**	**8.6**	**8.7**	**8.9**	**9.1**	**9.3**	**9.5**	**9.7**
Fleet	*GRAM-Other*	*11.4*	*12.1*	*8.6*	*8.2*	*8.4*	*8.6*	*8.7*	*8.9*	*9.1*	*9.3*	*9.5*	*9.7*
IT		**1**	**7.8**	**16.4**	**17.8**	**3.7**	**3**	**3**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**
IT-IT (Base Business)	*GRAM-Other*	*1*	*1.9*	*3.5*	*2*	*3*	*3*	*3*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*
IT-IT (Enterprise Asset Management)	*GRAM-Other*	*0*	*5.9*	*13.0*	*15.8*	*0.7*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Gas Ops (excluding Cherokee LNG Expansion)		**18.4**	**19.2**	**8.7**	**20.7**	**30.1**	**26.3**	**16**	**13**	**13**	**14.1**	**15.1**	**16.1**
Gas Ops-Measurement Ops (SCADA, Ctrls)	*GRAM-Other*	*2.9*	*1.9*	*2.2*	*2.2*	*2.3*	*1*	*1*	*1*	*1*	*1.1*	*1.1*	*1.1*
Gas Ops-Peaking (LNG, Propane, Compression)	*GRAM-Other*	*15.5*	*17.4*	*6.5*	*18.4*	*27.8*	*25.3*	*15*	*12*	*12*	*13*	*14*	*15*
Strategic		**0**	**3.1**	**1.5**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
STRAT-Strategic (CNG Stations)	*GRAM-Other*	*0*	*3.1*	*1.5*	*1*	*1*	*1*	*1*	*1*	*1*	*1*	*1*	*1*
STRAT-Strategic (Other)	*GRAM-Other*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Periodic Testing of Meters		**7**	**6.8**	**6.8**	**7**	**7.2**	**7.4**	**7.6**	**7.8**	**7.9**	**8.1**	**8.1**	**8.1**
PT Meter	*GRAM-Other*	*7*	*6.8*	*6.8*	*7*	*7.2*	*7.4*	*7.6*	*7.8*	*7.9*	*8.1*	*8.1*	*8.1*
System Renewals (GRAM-Other)		**13.3**	**7.7**	**8.4**	**9.3**	**10.3**	**10.7**	**11**	**11.2**	**11.4**	**11.6**	**11.9**	**12.1**
RENEW-General Renewals	*GRAM-Other*	*11.5*	*5.4*	*5.5*	*5.4*	*5.4*	*5.1*	*5.2*	*5.3*	*5.4*	*5.5*	*5.6*	*5.7*
RENEW-Remote-Controlled Valves	*GRAM-Other*	*0*	*0.4*	*1*	*2*	*3*	*4.1*	*4.2*	*4.2*	*4.3*	*4.4*	*4.5*	*4.6*
RENEW-Emergency Districts	*GRAM-Other*	*0.9*	*0.9*	*0.8*	*0.8*	*0.8*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*0.6*
RENEW-Exposed Mains	*GRAM-Other*	*1*	*1*	*1*	*1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.2*	*1.2*	*1.2*
Operations Support Capital Work		**3.9**	**3.8**	**3.8**	**3.7**	**5.2**	**5.1**	**5.1**	**21.6**	**21.9**	**21.7**	**21.8**	**8**
OPS-Bollards	*GRAM-Other*	*2*	*2*	*2*	*1.8*	*1.8*	*1.5*	*1.5*	*1.5*	*1.4*	*1.2*	*1.3*	*1.3*
OPS-ERT / AMR	*GRAM-Other*	*1.2*	*1.2*	*1.2*	*1.2*	*2.7*	*2.9*	*3*	*19.5*	*19.8*	*19.8*	*19.8*	*6*
OPS-Blanket Service Renewals	*GRAM-Other*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*
Pressure Regulating Facilities, Heaters, & Odorization		**27.7**	**27.7**	**29**	**32.5**	**32**	**27.3**	**27.8**	**28.4**	**28.9**	**29.5**	**25**	**25**
REG STN-Regulator Station	*GRAM-Other*	*22.2*	*22.2*	*25*	*30*	*32*	*27.3*	*27.8*	*28.4*	*28.9*	*29.5*	*25*	*25*
REG STN-RSRP Program	*GRAM-Other*	*5.5*	*5.5*	*4*	*2.5*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
Retirements (Removals)		**16.1**	**15**	**15.6**	**16.6**	**19.7**	**19.7**	**19.7**	**19.8**	**19.8**	**20.3**	**20.3**	**20.3**
REMOV-Removals	*GRAM-Other*	*14*	*12.9*	*13.5*	*14.5*	*17.5*	*17.5*	*17.5*	*17.5*	*17.5*	*18*	*18*	*18*
REMOV-Removals (inactive services)	*GRAM-Other*	*2.1*	*2.1*	*2.1*	*2.1*	*2.2*	*2.2*	*2.2*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*
Capitalized Tool Purchases		**1.1**	**1.4**	**1.7**	**1**	**1**	**1.1**	**1.2**	**1.1**	**1.2**	**1.1**	**1.2**	**1.2**
Tools (blankets, NB, Field, Con Ops)	*GRAM-Other*	*1.1*	*1.4*	*1.7*	*1*	*1*	*1.1*	*1.2*	*1.1*	*1.2*	*1.1*	*1.2*	*1.2*
RB - Overheads & AFUDC		**31**	**35.5**	**42.9**	**47.2**	**48.2**	**46.1**	**44.3**	**45.6**	**46.8**	**47.7**	**49.1**	**49.6**
RB-RB Overheads & AFUDC	*GRAM-Other*	*31*	*35.5*	*42.9*	*47.2*	*48.2*	*46.1*	*44.3*	*45.6*	*46.8*	*47.7*	*49.1*	*49.6*
Pressure Improvements (GRAM-Other)		**8.2**	**8.4**	**10.4**	**10.6**	**10.8**	**11**	**11.2**	**11.5**	**11.7**	**11.9**	**12.1**	**12.4**
Pressure Improvement (PRIM) - GRAM	*GRAM-Other*	*8.2*	*8.4*	*10.4*	*10.6*	*10.8*	*11*	*11.2*	*11.5*	*11.7*	*11.9*	*12.1*	*12.4*
Budget Category 3: System Reinforcement Rider (SRR)		**23.9**	**16.3**	**51.9**	**69.0**	**68.3**	**78.0**	**73.9**	**69.4**	**71.4**	**67.4**	**71.8**	**75.4**
Pressure Improvements (SRR)		**16**	**11**	**9.5**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pressure Improvement (PRIM) - SRR	*SRR*	*16*	*11*	*9.5*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
System Reinforcement - SRR Projects		**7.9**	**5.3**	**42.4**	**69**	**68.3**	**78**	**73.9**	**69.4**	**71.4**	**67.4**	**71.8**	**75.4**
SYS RE-Major Pipelines	*SRR*	*7.9*	*5.3*	*42.4*	*68*	*67.3*	*76*	*63.2*	*44.4*	*46.4*	*62.4*	*71.8*	*75.4*
SYS RE-Cherokee LNG Expansion Pipelines	*SRR*	*0*	*0*	*0*	*1*	*1*	*2*	*10.7*	*25*	*25*	*5*	*0*	*0*
Budget Category 4: Cherokee LNG Expansion		**25**	**25.1**	**50.7**	**75.1**	**82.4**	**0.3**	**0**	**0**	**0**	**0**	**0**	**0**
Gas Ops (Cherokee LNG Expansion)		**25**	**25.1**	**50.7**	**75.1**	**82.4**	**0.3**	**0**	**0**	**0**	**0**	**0**	**0**
Gas Ops-Cherokee LNG Expansion	*GRAM-Other*	*25*	*25.1*	*50.7*	*75.1*	*82.4*	*0.3*	*0*	*0*	*0*	*0*	*0*	*0*
Total AGLC Capital (Distribution Ops + Corp)		**434**	**440.2**	**497**	**579.6**	**588.1**	**538.5**	**505.7**	**511.6**	**517.4**	**523.2**	**529.4**	**534.8**

Figure 8: Proposed Capital Investment by Budget Subcategory/Program



5.5. Overview of Planning and Project Selection Process

Each year, generally in July, the Company begins the detailed capital budgeting process for the following year, as well as a higher-level budget exercise for a full ten years. This timeline was accelerated in 2020 to start in May to meet the July 1, 2020 GRAM filing deadline with additional refinements through August as a part of the normal budgeting process. To provide the most up-to-date and accurate budget for this filing, the official budget was revised at the end of 2020 to reflect current project schedules and costs as well as new projects since mid-2020.

The budgeting process begins within the Engineering & Construction (E&C) organization. E&C coordinates the development of the capital budget by consolidating projects from all functional areas across the Company. A capital budgeting template is provided to each functional area to allow for submission of capital requests. These submissions are grouped by budget subcategories (e.g. DOT, New Business, Pressure Improvement, etc.) and include key fields such as:

- Budgeting owner and department
- Project name
- Project description and justification
- Prioritization Category and Criticality (see below)
- Estimated monthly costs
- Estimated full-year costs

The first step in prioritizing which projects will be completed begins with assigning a prioritization class and a criticality to each line item. The matrices on the following page are utilized to consistently apply these prioritizations focusing first on safety and compliance.

Table 8: Matrix of Project Criticality and Class

AGL 2021 CAPITAL PRIORITIZATION

Class	Criticality: MUST DO (1)	Criticality: SHOULD DO (2)	Criticality: SHOULD DO LATER (<3 YRS) (3)
Safety (A)	Documented incident *will require* a response involving capital funding in the plan year.	Identified risk to our personnel, the public or our property is high and *there is no* acceptable, cost effective alternative.	Identified risk to our personnel, the public or our property is high *but there is* an acceptable, cost effective alternative; or identified risk to personnel, the public or property is low.
Regulatory (B)	A non-compliant regulatory or contractual condition exists in the current year but acceptable plans have been filed that *will require* capital funding to achieve compliance in the plan year.	A non-compliant policy condition will occur in the plan year or, the company's reputation will be at risk at a high level unless action is taken and *there is no* acceptable, cost effective alternative.	A non-compliant regulatory, contractual or policy condition will occur in the plan year *but there is* an acceptable, cost effective alternative; or, the company's reputation will be at risk at a low level unless action is taken.
Reliability and Integrity (C)	A pipeline operations asset or service has failed and *will require* capital funding to meet operating needs in the plan year.	Required to meet BU strategy for growth or a pipeline operations asset that is likely to need replacement in the plan year (based on failure history) to meet operating needs and *there is no* acceptable, cost effective alternative.	Same as 2C *but there is* an acceptable, cost effective alternative; or, current operating rates do not require that this unit be maintained for immediate in-service readiness.
Obsolescence and Upgrades (D)	Not Applicable.	Equipment which has reached end-of-life, no longer supported by any vendor *and* spare parts are no longer available. May generate spare parts for other locations.	Same as 2D *but there are* spare parts available from other locations.
Productivity (E)	Carryover for projects currently in process based on prior year business cases.	Analysis of project economics indicates 10.9% or better ROE.	Analysis of project economics indicates less than 10.9% ROE.
Business Projects & Programs (F)	Policy Committee approved company project for the plan year that will require resources, complete all deliverables and begin to accrue "value" in the plan year.	Policy Committee approved company project for the plan year that will require resources in the plan year and year two, completes some deliverables in the plan year and will begin to accrue "value" in year two.	Policy Committee approved strategic and multi-year programs that will require resources for more than two years, but does not begin to accrue "value" until year three.
Contingency Funds (G)	Contingency funds for unspecified requirements.	Not Applicable.	Not Applicable.

Table 9: Matrix of Project Criticality and Class

Class	Criticality		
	MUST DO (1)	*SHOULD DO* (2)	*SHOULD DO LATER (<3 YRS)* (3)
Safety (A)	1A	2A	3A
Regulatory (B)	1B	2B	3B
Reliability and Integrity (C)	1C	2C	3C
Obsolescence and Upgrades (D)	1D	2D	3D
Productivity (E)	1E	2E	3E
Business Projects & Programs (F)	1F	2F	3F
Contingency Funds (G)	1G	2G	3G

E&C then consolidates all budget submissions and compares the total requests against current long-range budgets, previous rate case and/or GRAM filings, and any additional guidance from the Company's Regulatory and Financial Planning & Analysis departments. A series of budget reviews are then completed to refine the requests using the prioritizations as well as guidance from E&C leadership.

Once these efforts are completed, a budget summit is held which includes the utility president and vice presidents of Operations, Regulatory, Financial Planning & Analysis, and leaders from all capital related departments. Each functional area presents details supporting their budgeted items as well as any concerns around items that may have not been funded. Once all questions and concerns have been resolved and any necessary adjustments made, the budget is presented and approved by Company leadership.

5.6. Peaking Projects – Existing LNG Facilities

I. Introduction:

The Company's LNG plants are critically important to meeting AGL's customers' needs. When AGL's customers use more natural gas than interstate gas pipelines can deliver, the LNG plants vaporize gas into the distribution system to maintain system pressures and meet customers' needs on the coldest days of the year. AGL has three LNG plants: Cherokee, Riverdale, and Macon. Together they can provide about 35% of the gas consumed on a design day.

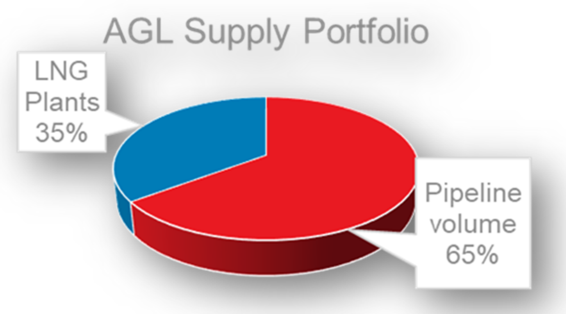


Figure 9: AGL Supply Portfolio on a Design Day

II. Present Drivers:

The Riverdale, Macon, and Cherokee plants were constructed in 1972, 1977, and 1988, respectively. They are all beyond their expected service life of 25 years. Much of the equipment and materials in these plants have lead times of multiple months or longer from order to installation, making it imperative that AGL replace this equipment prior to failure. Failure to do so could result in the plant not being operable on those peak gas demand days and thereby jeopardizing gas supply to thousands of AGL customers when they need it most. Also, in refurbishing the plants with modern equipment, improvements in safety, reliability and performance are realized. The Company proposed in the 2019 rate proceedings and is currently executing on a proactive, a multi-year approach to replacing and upgrading this equipment at the three plants.

These improvements can be categorized as:

- Like-for-like replacement of end-of-life and obsolete equipment such as replacing a single pump or generator
- Replacement of end-of-life and obsolete systems that require bringing the system up to current codes and standards such as replacement of the fire protection systems, which now need to be brought up to current National Fire Protection Association (NFPA) 59A standards.

With the severe limitations on additional peaking supply from interstate pipelines and the increased reliance on LNG through the proposed Cherokee LNG expansion, AGL has proposed a significant increase in investment in these facilities to help ensure that they continue to safely, economically, and reliably provide the necessary peaking supplies into the system on the coldest days of the year.

III. Funding Requirements:

While there are many smaller capital replacement items proposed for these plants included in the current budget, below is a listing of the major planned projects for each of these facilities through 2024:

- The critical components at the Riverdale LNG plant that are planned for replacement include the liquefaction system, sendout pumps and boil off compressors. The new liquefaction system will increase reliability and productivity and includes the pretreatment vessels, valves & piping, the cold box & expander system, and the reactivation heater. The new sendout pumps will be electric driven and common to both tanks. New 4160V generators will be installed to provide power for either the sendout pumps or new tailgas compressor, with utility power as a backup power source. The boil off compressors are original equipment to the facility and currently operate without redundancy.
- At the Cherokee LNG plant, a replacement of the liquefaction system and the addition of a boil off compressor are planned. The liquefaction system includes the pretreatment vessels and the cold box. A full-size redundant electric boil off compressor will be installed to increase reliability of the system. Currently, the liquefaction system replacements and new boil off compressor are being evaluated for consolidation with the Cherokee LNG expansion project to create efficiencies with both construction and cost. Should these evaluations result in a decision that it is beneficial from an economic, environmental, and/or other consideration due to efficiencies that can be achieved with the new equipment installations, AGL will propose reallocation of the appropriate budgets from the Gas Ops-Peaking budget line to the Cherokee LNG expansion project accordingly.
- The major projects at the Macon LNG plant include replacement of the firewater system, a new sendout pump & vaporizer, and replacement of the liquefaction compressor and generators. The updated firewater system will include new piping, hydrants, and monitors. A new sendout pump and vaporizer will be added to increase system resiliency.

Replacement of the liquefaction compressor and generators are needed to maintain system reliability.

Table 10: Peaking Budget

Peaking (LNG, Propane, Compression) ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	3.7	9.7	22.8	15.5	17.4	6.5	18.4	27.8	25.3	15.0	12.0	12.0	13.0	14.0	15.0

5.7. Peaking Projects – Cherokee LNG Expansion

I. Introduction:

As outlined in chapter 4.3 of this document, it is prudent and necessary to expand the Cherokee LNG plant to meet customer demands. Fortunately for AGL and its customers, the designers of the Cherokee LNG plant had the foresight in 1988 to build the facility with the necessary land and footprint to allow for expansion.

II. Present Drivers:

The current plant has a single tank capable of storing two billion cubic feet (2 Bcf) of natural gas with a sendout capacity of 400,000 dekatherms per day. The proposed expansion would add a second 2 Bcf tank and the necessary facilities to add an additional 400,000 Dth per day of send-out capacity. The expansion would include the following:

- New 2 Bcf tank
- New liquefaction train with pretreatment system
- Additional send-out vaporization equipment
- Expansion of power generation system to support additional equipment loads

III. Funding Requirements:

While the Company is still in the design and permitting process, the project is currently estimated at approximately $234 million (before overheads, AFUDC, and internal labor, which are added in Table 8 and Table 9 below). Based on current system modeling, an additional system reinforcement project (Cumming to McGinnis Ferry) will have to be constructed by 2028 to be able to push the full additional 400,000 Dth into the system in time meet the projected demand and to resolve system pressure issues in this area. Early estimates for this project are approximately $70 million (see below for current estimated investments and timing).

Table 11: Cherokee LNG Budget

Cherokee LNG Expansion ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	0.0	0.0	0.4	25.0	25.1	50.7	75.1	82.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0

Table 12: System Reinforcement – Cherokee LNG Expansion Pipelines

System Reinforcement - Cherokee LNG Expansion Pipelines ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	2.0	10.7	25.0	25.0	5.0	0.0	0.0

The funding for the LNG facility expansion is included within the Gas Ops section of the budget. The funding for the associated Cumming to McGinnis Ferry pipeline project is included within the System Reinforcement section of the budget, inasmuch as that system reinforcement is separately needed to support existing and future customers' needs.

Table 10 and Table 11 below outline the currently estimated timelines, associated additional capacities, and estimated cost breakdowns as of January 2021 for the major phases/components of the expansion project.

Table 13: Phases and Components of LNG Facility Expansion

		Current	2nd Tank, Tank BOP, and Generators in Service	New Liquefaction System in Service	Additional Vaporization Equipment	Cumming-to-McGinnis Ferry Improvements
	In-service Date	2021	Q4 '23	Q2 '24	Q2 '25	Summer '28
Design Send Out	Dth/day	400,000*	520,000	520,000	740,000***	800,000
Peak Send Out	MSCFH	26,000*	26,000	26,000	42,000	42000
Storage	BSCF	2	2.6**	4	4	4
Inventory	Days @ Design Send Out	5	5.0	7.7	5.6	5.0
Liquefaction	MMSCFD	10	10	20	20	20
Budget	$ million	[redacted]	128.06	49.59	57.78	[redacted]

*Design rate reflects send out of full tank inventory over 5 days. Peak send out capacity includes operational reserve margin above design send out capacity.
** Reflects partially filled new tank by Jan. '25
***Limited by distribution system

Table 14: Annual Spend Analysis

Annual Spend Analysis						
	2020	2021	2022	2023	2024	2025
Tank	$ 222,637	$ 17,552,870	$ 40,921,826	$ 17,812,957	$ 1,440,000	$ 180,000
Tank BOP	$ 44,880	$ 283,824	$ -	$ 9,537,213	$ -	$ -
Power	$ 44,880	$ 495,672	$ 5,854,028	$ 17,562,084	$ -	$ -
Vaporization	$ 44,880	$ 137,500	$ 651,659	$ 5,314,787	$ 37,205,510	$ -
Liquefaction	$ 44,880	$ 137,500	$ 755,481	$ 15,493,402	$ 34,085,484	$ -
Contingency	$ -	$ 3,024,157	$ 6,278,117	$ 9,609,066	$ 10,691,349	$ -
Sub Total	**$ 402,157**	**$ 21,631,523**	**$ 54,461,111**	**$ 75,329,509**	**$ 83,422,343**	**$ 180,000**
T - Overhead Allocations	$ 44,254	$ 1,583,950	$ 3,981,107	$ 5,506,587	$ 6,098,173	$ 13,158
X - Capitalized Interest	$ 7,676	$ 547,055	$ 4,754,116	$ 10,394,264	$ 9,586,227	$ -
Sub Total	**$ 51,930**	**$ 2,131,005**	**$ 8,735,224**	**$ 15,900,851**	**$ 15,684,401**	**$ 13,158**
Grand Total	**$ 454,087**	**$ 23,762,528**	**$ 63,196,335**	**$ 91,230,360**	**$ 99,106,744**	**$ 193,158**
Direct	**$ 402,157**	**$ 22,033,679**	**$ 76,494,790**	**$ 151,824,299**	**$ 235,246,642**	**$ 235,426,642**
Total	**$ 454,087**	**$ 24,216,615**	**$ 87,412,949**	**$ 178,643,309**	**$ 277,750,053**	**$ 277,943,211**

5.8. Strategic Delivery Projects

I. Introduction:

AGL, in coordination with the Commission and the Staff, devotes considerable attention to improving access and service to unserved and underserved areas. Strategic pipeline projects, all individually approved by the Commission under current USF and Econ-1 programs, provide development and job growth opportunities to these areas and likely would not be possible without these programs. Additionally, AGL makes strategic investments in Compressed Natural Gas (CNG) stations. These stations range from AGL fueling stations serving Company CNG vehicles to key commercial and transportation customers.

II. Present Drivers:

AGL's line extension policies under the current Tariff provide a set amount of "Allowable Investment" that AGL will invest to serve the customer based on their anticipated gas usage. This allowable investment is adequate in most cases to fund projects near existing gas facilities. However, potential customers, developments, and even towns on the outskirts of the existing AGL system may require significant pipeline investments to get natural gas to their area, which cannot be supported by one or even a few new loads. This can essentially limit access to natural gas, and in many cases, limit the area's ability to attract industry to support economic growth and jobs.

Programs such as USF and Econ-1 may provide additional funding to support these strategic extensions, provided that the projects meet the criteria for these programs, which may include minimum load requirements and commitments and even anticipated additional jobs created. As illustrations, AGL has supported poultry industry expansions in Banks, Appling, Gilmer, and Macon counties. There are also current projects to feed new and expanding industrial facilities in multiple counties outside of the Metro Atlanta area including Floyd, Banks, Appling, Jeff Davis, Walker, and Clinch counties.

The current 2021 and 2022 investment in CNG facilities is primarily related to a new station that AGL is designing and constructing in 2021 under the V-52 tariff rate for Chesapeake Utilities Corporation at the Port Fueling Center in Savannah, Georgia and for a second station that will be designed and constructed to fuel AGL fleet vehicles at its Marietta Regional Business Center currently planned for 2022 to coincide with the overall facility replacement. The Port Fueling Center CNG Station will provide natural gas fueling options for Class 8 trucks moving cargo in and out of the port, yard tractors and other equipment both on-port and in surrounding logistics centers, and for CNG trailers for mobile fuel and virtual pipeline solutions. Proposed investments beyond 2022 represent a placeholder for available investment funding for future projects.

III. Funding Requirements:

There is not a specific budget for USF and Econ-1 projects so there is not a specific request for capital funding for these expansions. The Commission approves AGL's proposal for USF projects and, thereafter, the Company begins installation. AGL is reimbursed for the investment through the Commission controlled USF. Additionally, Econ-1 projects are individually approved by the Commission within the terms of the program and AGL is allowed to recover project investments, in addition to the current approved capital budget, through rates.

AGL requests that the Commission continue its emphasis on economic development by continuing to approve USF and Econ-1 projects funded through these existing Commission approved and audited mechanisms to provide clean, safe, and reliable natural gas to these unserved and underserved areas in Georgia.

The current and proposed budgets for Strategic CNG station work are included below. It should be noted that AGL is currently in conversations with the Metropolitan Atlanta Rapid Transit Authority (MARTA) to potentially make major upgrades to multiple aging CNG bus refueling facilities. While the details and funding mechanisms are yet to be determined, it is possible that investments in this area will have to significantly increase based on these determinations if the projects move forward.

Table 15: Strategic CNG Stations Budget

Strategic - CNG Stations ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	0.3	1.1	0.5	0.0	3.1	1.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

5.9. New Business

I. Introduction:

AGL continues to support new customer growth and existing customer expansions through its New Business Tariff. These investments support economic development and jobs across the state while providing clean, affordable natural gas to residential, commercial, and industrial customers.

II. Present Drivers:

The quantities and costs of this work have increased in recent years requiring significantly more capital investment. There are three primary cost drivers requiring additional spending for new services. The first cost driver is AGL's significant increase in growth since 2012 represented by actual new meter increases in the table below.

Table 16: New Meters

AGLC New Meter Additions								
Historic Actuals								
2012	2013	2014	2015	2016	2017	2018	2019	2020
8,311	11,676	14,182	16,036	17,891	17,740	19,690	18,539	17,076

Second, several new quality/safety processes have been added (or enhanced) for each new service installed including:

- Requiring the expanded use of excess flow valves or curb valves on all new services (PHMSA mandate)
- Proactively using robotic cameras and other technology to locate sewer mains and laterals prior to the installation of AGL's new gas mains and services

- Increasing the use of vacuum excavation and/or hand digging due to development density, utility congestion, and to increase safety
- Increasing recordkeeping and documentation requirements

Each of these new quality/safety processes have added costs.

Third, AGL has seen increased skilled labor costs due to inflationary pressures associated with a strong economy, increased construction work in all sectors, and significant increases in new pipeline construction.

While this growth and related cost pressures have slowed a little due to COVID-19, especially in the small commercial sector, there continues to be a shortage of available housing. The demand for additional housing, coupled with Georgia's business friendly environment, is expected to drive continued new business growth for years to come.

III. Funding Requirements:

The table below contains current estimates for serving anticipated New Business growth. Note: The 2021 Strategic New Business line is for the estimated portion of the Commission approved International Paper USF project that is expected to be included within rate base.

Table 17: New Business Budget

New Business (incl. Strategic, OH, & AFUDC)	**2018**	**2019**	**2020**	**2021 (GRAM)**	**2021 (Bud)**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	82.2	**76.4**	**83.8**	**86.0**	**100.9**	**78.6**	**81.6**	**81.9**	**82.0**	**81.8**	**80.0**	**79.1**	**80.4**	**81.5**	**83.4**
Core New Business	*74.6*	*68.0*	*67.9*	*69.4*	*68.4*	*72.8*	*76.1*	*76.2*	*75.9*	*75.4*	*73.6*	*72.7*	*73.7*	*74.6*	*76.5*
Strategic New Business	*(0.5)*	*1.2*	*7.5*	*8.8*	*23.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Overheads & AFUDC	*8.0*	*7.1*	*8.3*	*7.8*	*9.5*	*5.8*	*5.6*	*5.7*	*6.2*	*6.5*	*6.4*	*6.4*	*6.6*	*6.9*	*7.0*

5.10. System Reinforcement

I. Introduction:

Because of continuing customer growth and the expansion of metropolitan areas in Georgia, there is an ongoing need for system reinforcement to bring natural gas from interstate supply points to the customers' locations. Historically, the Commission has shown great foresight on system reliability and customer growth by approving the STRIDE program, particularly the i-SRP part of STRIDE since 2010. Under the STRIDE program, AGL completed system reliability projects in Coweta, Fulton, Cobb, Gwinnett, Cherokee, Forsyth, and Paulding counties to bolster the system during extremely cold weather. As customer growth continues, further system improvements will be required.

II. Present Drivers:

AGL's System Planning Group analyzes flow and pressure data to ensure reliable service to customers. Using simulations based on historical and projected growth, AGL can anticipate where outages or low pressures are likely to occur. The models are flexible and can allow multiple growth projection, load migration, and extreme weather condition scenarios. The models are used to determine the areas that need additional capacity.

III. Funding Requirements:

AGL has determined that system reinforcement projects are necessary in multiple greater Metro Atlanta counties to maintain reliable system performance in instances of extreme cold weather.[10] These counties have experienced significant population growth and are all considered part of the Atlanta metropolitan region.

The following projects are included in AGL's 10-year Plan (2021-2031):

- McGinnis Ferry Road
- Wade Green Road Phase 2
- Cumming to Hall County
- High Point to Villa Rica
- Villa Rica to Temple
- Temple to Bremen
- NW Ga Line to Rome #1
- Cumming to McGinnis Ferry Road
- Ball Ground to Ellijay

[10] The details for these system reinforcement projects, including the counties where the projects are located, are available in the Company's Supplemental Minimum Filing Requirements for this i-CDP.

- Camp Creek to Fulton Industrial Blvd
- Hall County Extension

AGL has included $5.3 million in its 2021 capital budget and $42.4 million in its 2022 capital budget to undertake the projects below to improve AGL's system reliability in these areas. The plan details the full 10-year request for these projects, as well as future unidentified projects. Although System Reinforcement spend is lower in 2021 due to other capital priorities, significant increases will be needed in 2022 and beyond to complete many of the projects listed above, with projects such as Cumming to Hall anticipated to cost over $100 million to complete. Delaying these projects would significantly increase the risk of customer outages in the counties listed above.

It should also be noted that the System Reinforcement capital submission in the current GRAM filing also includes funding for the AC Mitigation and Shorted Casing programs. With the introduction of the SRR, the Shorted Casings and AC Mitigation budgets have been removed from the System Reinforcement budget and placed in their own budget lines for clarity, as outlined in section 5.21.

Table 18: System Reinforcement Budget

System Reinforcement *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	32.3	**22.3**	**39.2**	**7.9**	**5.3**	**42.4**	**69.0**	**68.3**	**78.0**	**73.9**	**69.4**	**71.4**	**67.4**	**71.8**	**75.4**
Major Pipelines	*32.3*	*22.3*	*39.2*	*7.9*	*5.3*	*42.4*	*68.0*	*67.3*	*76.0*	*63.2*	*44.4*	*46.4*	*62.4*	*71.8*	*75.4*
Cherokee LNG Expansion Pipelines	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*1.0*	*1.0*	*2.0*	*10.7*	*25.0*	*25.0*	*5.0*	*0.0*	*0.0*

5.11. Distribution Integrity Management Program (DIMP)

I. Introduction:

The objective of the DIMP is to comprehensively assess and address the integrity of the distribution system. As part of the DIMP, the Company has annually identified threats to its distribution system, determined the relative risk of each of the identified threats, and has developed actions to mitigate those risks. AGL quantifies and ranks these risks through a combination of data analysis and subject matter expert interviews. The results of these assessments have determined that older steel (pre-1960) and mid-vintage plastic (1974-1983) pipelines pose an elevated risk to the distribution system and should begin to be renewed.

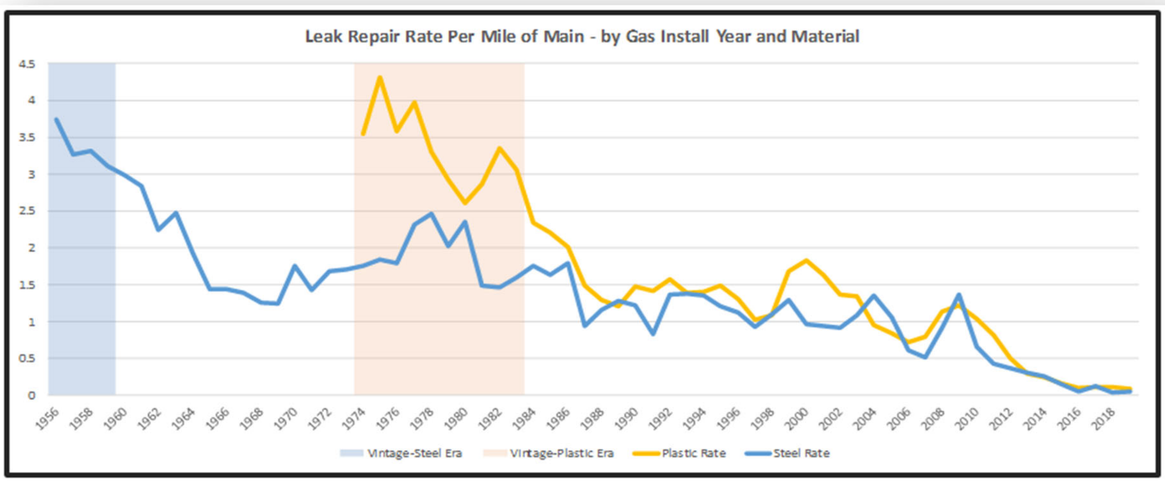
II. Present Drivers:

The increased leak rate on mid-vintage plastic pipelines is often caused by the pipe material becoming brittle, making it subject to more frequent cracking leaks. Accordingly, the risks associated with the earliest vintage plastic was the basis for the Commission approved Vintage Plastic Replacement ("VPR") Program that was completed in 2017. This program included the replacement of pre-1974 plastic mains and some of the highest risk mid-vintage plastic (1974-1983).

The first steel pipeline coatings used by the industry back in the 1950's were not as durable as modern steel pipe coatings. Consequently, this material has also demonstrated an elevated leakage rate compared to more modern steel and plastic pipe materials.

The chart below includes leaks per mile of steel and plastic gas main by year of installation based on recent leak survey results. The shaded areas highlight the pre-1960 time period, as well as the 1974-1983 time period that was not addressed in the VPR program mentioned above. As illustrated below, steels installed pre-1960 and mid-vintage plastics installed in 1974-1983 exhibit the highest leak rates within the AGL system.

Figure 10: Leak Repair Rate Per Mile of Main



Leak Rate Metric:

- Leak Rate represents leak per mile of active Gas Main by year installed and material. Excavation, outside force, above ground, and meter set leak repairs are excluded.

III. Current DIMP Process

A multi-tiered approach to risk ranking has been developed to evaluate the risks associated with the distribution pipeline. This more sophisticated risk analysis approach has been created to better understand and react to threats occurring in the system. This approach ensures all threats and the potential consequences are considered and addressed in a manner appropriate with the threat.

A risk analysis hierarchy has been provided to allow for macro and micro understanding of threats in the system. Accordingly, the risk analyses provide different perspectives where threats may be identified and addressed.

Table 19: Risk Evaluation

Risk Evaluation	System / Local	Update Frequency
System Level Threat Assessment	System	Annually
Subject Matter Expert Risk Assessment	System/Local	Annually
Pipeline Integrity Risk Assessment	Local	Annually
PHMSA Audit Risk	System/Local	Annually

The **System Level Threat Assessment** considers leak sub-causes per facility type. The trend (likelihood of failure), frequency (likelihood of failure), and hazardous percentage (consequence of failure) of all leak repairs in the system to calculate a risk score.

The **Subject Matter Expert Risk Assessment** is performed by region, material, and sub-cause. This assessment considers all threats, leak repairs, and SME background knowledge to determine a relative score for both (consequence of failure) and (likelihood of failure) to calculate a risk score.

The **Pipeline Integrity Risk Assessment** assigns a risk score based on geographical location to each segment/neighborhood. This assessment is geospatially aware which means the cause and consequence scores are unique to the geographical location of the pipeline. The risk model uses both the attributes of the pipeline, premises, business district, and leak data while considering the physical location of the data to produce geographically accurate risk scores. For example, large and high-pressure pipelines in an urban area have a higher consequence of failure score and vintage material pipelines will have a higher likelihood of failure score than pipelines made with more modern materials.

The **PHMSA Audit Risk** report is comprised from the System Level Threat Assessment and the Subject Matter Expert Risk Assessment. This approach ensures that leak volumes and SME expertise are considered when determining the top risks to the distribution system.

IV. Funding Requirements:

As of the end of 2019, AGL had 1,559 miles of known or assumed to be pre-1960 coated steel mains and 2,602 miles of known or assumed to be mid-vintage plastic mains in its system. The estimated costs to replace these facilities is approximately $1.9 billion. This was addressed in the 2019 AGL rate case filing (Docket No. 42315; Pre-Filed Direct Testimony of Steve Murphy, Jennifer Rose, Don Carter, and Bradley J. Beckman on Behalf of Atlanta Gas Light Company). At that time, AGL proposed spending around $30 million annually but stated the following:

> "*At this investment level, it will take more than 50 years to replace these pipelines, which the Company recognizes is too long from a pipeline safety perspective, particularly if more segments begin to develop more leaks in the future. Therefore, the Company acknowledges that in the future, higher funding levels must be devoted to accelerate replacement of this higher risk pipe.*"

As can be seen in the table below, proposed DIMP spending in 2021 has been reduced significantly from the rate case proposed levels to allow for other higher priority projects related to compliance and system stability to be completed. This spending is proposed to increase in future years but will continue to have to be prioritized against other needs. The spending level will likely not reach the ideal $75 million per year investment level necessary to complete this work within the preferred 25 to 30-year timeframe without additional dedicated funding similar to the previous Vintage Plastic or Bare Steel and Cast-Iron replacement programs approved by the Commission.

Table 20: DIMP Budget

DIMP *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	22.6	13.4	19.0	16.1	15.8	20.6	24.9	30.0	35.0	39.9	39.6	38.9	42.4	45.7	50.2

5.12. Gas Operations

I. Introduction:

Gas Operations - Measurement & Controls

The mission of the Measurement & Controls department within Gas Operations is to provide safe, reliable, and cost-effective flow measurement of natural gas to AGL's end-use customers. The Measurement & Controls group not only provides AGL customers with industry and American Gas Association approved measuring equipment but also ensures proper installation and calibration for the life of the devices. Measurement & Controls manages and supports the complete lifecycle of over 7,381 industrial gas meters, 368 transportation customer sites, and 86 Gate Stations for custody-transfer of natural gas from suppliers as well as overseeing the AGL PT Meter sampling program.[11] Gas Measurement & Controls is also responsible for the IT support of the control system used by Gas Control to monitor and safely deliver natural gas throughout the state of Georgia. Continued investment in the installation, upgrade, and replacement of these measuring and control facilities is necessary to ensure the safety, reliability, and accuracy of this equipment.

II. Present Drivers:

Major drivers of Measurement & Controls expenses and investments include regulatory requirements around end-use customer measurement equipment calibration, new customer count increases, and PHMSA/TSA cyber security guidelines.[12] With the recent rise in cyber security concerns and possible hacking threats, constant updating of electronic equipment used to measure, monitor, and control gas flow are expected to continue to increase over time.

Additionally, AGL has started a multi-year initiative to increase safety through remote monitoring of Mercaptan levels at approximately 35 locations where AGL receives odorized gas from pipeline suppliers. While AGL has and will continue to complete the required in-person verifications of the levels of odorant within its system per current code, the installation of real-time monitors at these

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[11] The PT Meter sampling program is described in section 5.20.

[12] The Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Transportation Security Administration (TSA), which are agencies within the U.S. Department of Transportation, announced an updated pipeline security agreement in February 2020, which resulted in new guidelines for the industry.

locations, coupled with 24/7 monitoring through AGL's Gas Control, will significantly reduce the risk of improper or inadequate odorant levels at these locations where the odorization is not managed by AGL.

III. Funding Requirements:

The proposed investment levels below include the normal run rate spending for these facilities along with near-term increases to implement remote monitoring and cybersecurity initiatives as outlined above.

Table 21: Gas Operations – Management & Control Budget

Measurement, SCADA, Controls ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	0.3	0.3	0.9	2.9	1.9	2.2	2.2	2.3	1.0	1.0	1.0	1.0	1.1	1.1	1.1

5.13. DOT Driven Facility Relocations

I. Introduction:

The majority of AGL's pipeline facilities are located within state, county, or municipal DOT road right-of-way. These facilities fall under right-of-way agreements that require AGL to relocate its facilities when necessary when there is a conflict with future roadway, drainage, or related construction. This roadway construction work is proposed, scheduled, and controlled by these government entities and the timing is heavily reliant on federal DOT funding and revenues from tax programs from state level gasoline taxes to Special Purpose Local Option Sales Taxes (SPLOSTs) for road construction which are generally at the County or regional level. AGL must conform to the state, county, or municipal governments' scheduling requirements.

There are two rare scenarios where AGL is reimbursed for gas facilities relocations driven by road construction work:

- AGL does obtain easements and/or purchases property outside of DOT right-of-way where possible for certain larger pipelines and critical facilities. If AGL facilities located within existing easements or Company owned property are determined to conflict with a DOT project, the DOT is required to reimburse AGL for the cost of the relocations as well as procurement of any necessary replacement easements or property.

- There are existing federal programs that allow for the State to reimburse utilities for DOT driven facility relocations, but these programs are rarely utilized and are solely at the State's discretion.

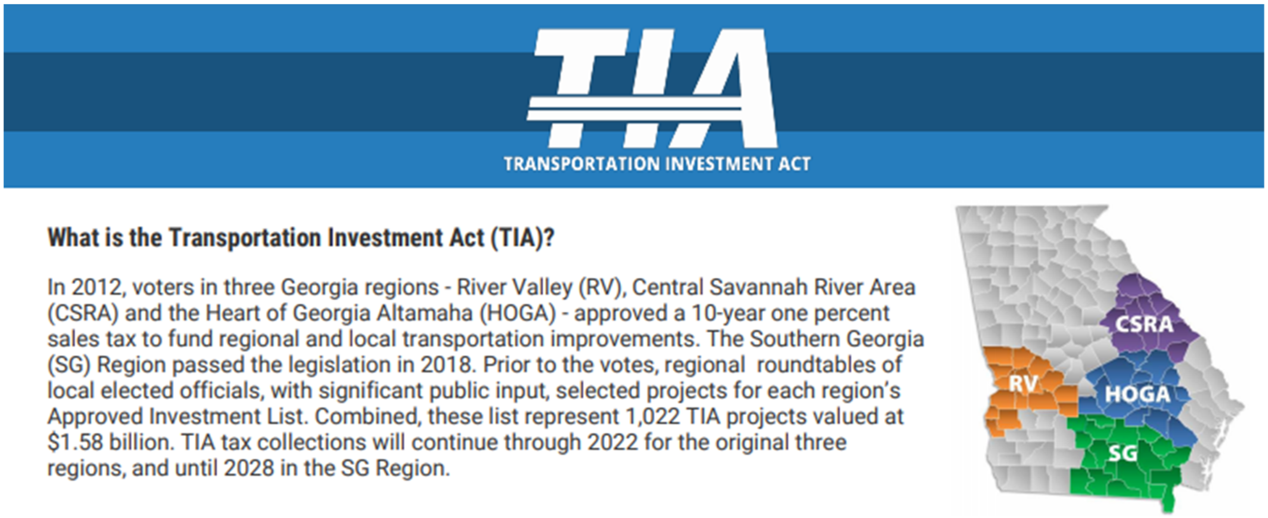
II. Present Drivers:

Most DOT related relocation costs for AGL are driven by projects funded with state gasoline tax revenues, county, or regional SPLOST programs, and federal funding for transportation.

Most SPLOST programs at the county level are approved by voters for multiple years at a time. SPLOST programs in some of the larger Metro Atlanta counties such as Gwinnett, Cobb, and Fulton can drive millions of dollars of required gas facility relocations each year. Examples of some of the larger county transportation SPLOSTs are included below:

- Cobb County – Current T-SPLOST was renewed by the voters in November 2020 and will run to December 31, 2027. The 2022-2027 SPLOST includes funding specifically for transportation projects totaling approximately $330 million over the six-year program along with city SPLOST estimations of another $183 million with a large portion of those dollars also supporting city DOT work.
- Gwinnett County – The current SPLOST runs through 2023 with an estimated $437.7 million for transportation projects.
- Fulton County – The current SPLOST runs through March 30, 2022 or when the maximum amount of $655 million is reached. Funding from this SPLOST can only be spent on transportation improvements.

There have also been multiple efforts to create regional tax revenue mechanisms to fund additional roadway expansions and upgrades. An example of this was the 2012 Statewide Transportation Referendum (see published program details below) which was voted on by regions of the state. In this case, regional programs were approved in three initial areas with $1.8 billion in estimated revenues over 10 years. Another region (South GA) was approved later and will run until 2028 further increasing the potential for impacts from these projects to existing AGL facilities.



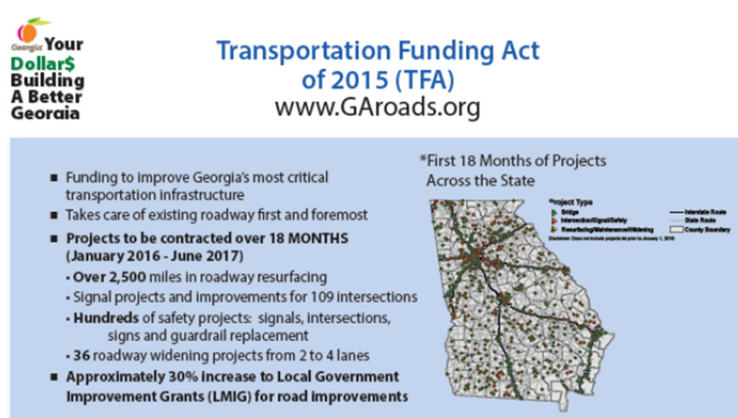
Graphic taken from GA DOT website: http://www.ga-tia.com/Content/pdf/TIA%20Admin%20FAQs.pdf

Federal funding initiatives provide additional dollars for interstate and other improvements. The amount of available funds can vary based on federal budgets, revenues, and programs intended to spur jobs and economic growth.

Finally, one of the largest and most stable funding sources for DOT projects is the state gasoline tax and related revenue. The Transportation Funding Act of 2015 (GA HB 170) included multiple funding sources including:

- Increase of the gas tax by 6 cents on 7/1/16 with additional escalators in the following years
- $5 per night hotel fee
- $200-$300 annual fee on electric vehicles
- $50-$100 fee on heavy trucks

According to the Georgia DOT via www.GAroads.org, these funding sources were expected to result in ~$1 billion of additional revenue to be used by GDOT for transportation. This essentially doubled the State's budget for road improvements and was a primary driver for AGL's actual DOT relocation spending going from $17.2 million in 2014 to $36.2 million in 2018.



These spending levels have remained consistent since that time with AGL DOT relocation costs of $30.5 million in 2019 and $28.2 Million in 2020 even with COVID related challenges.

III. Funding Requirements:

Since this work is required as a part of AGL's permit and right-of-way agreements with the State and other governmental agencies, AGL must perform this work regardless of other budgetary pressures or priorities. There has been a reduction in gasoline tax revenue due to COVID-19 driven home-basing of many Georgia employees, but that impact is currently expected to be temporary and may be offset by additional proposed federal spending on transportation aimed at spurring economic growth.

While AGL tries to minimize the costs of these projects where possible through subsurface utility engineering and other methods, expectations are that AGL's spending on DOT relocation projects will remain at these levels with a basic inflationary factor for the foreseeable future with a potential to increase should there be additional investment in this area at a federal level.

Table 22: DOT Budget

DOT *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	36.2	30.5	28.2	27.9	28.2	30.9	31.5	32.1	32.8	33.4	34.1	34.8	35.5	36.2	36.9

5.14. Pressure Improvements

I. Introduction:

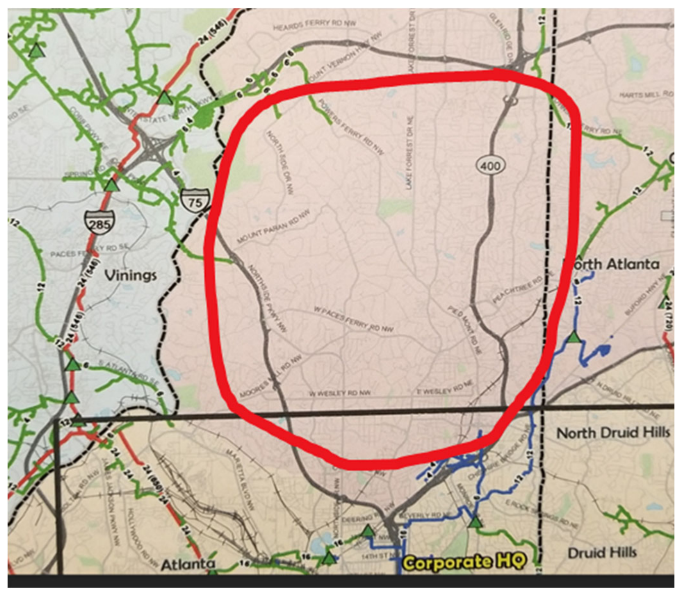
As new customers are added to the system and existing customers increase their usage of natural gas, this increased demand causes a reduction in the operating pressure of the system on higher demand days. On higher pressure distribution systems generally operating around 300 psi, this reduction in pipeline pressure reduces the capacity of the downstream regulating facilities, which limits the ability of the system to supply the necessary gas to local medium-high pressure systems generally operating at 60 psi. When medium-high pressure systems are constrained, pressures in these systems may fall below the minimums for customers' regulating facilities to properly operate or the system may experience a complete loss of pressure on a high demand day resulting in customer outages on the coldest days of the year.

As these system constraints are identified through pressure modeling and field measurements of actual pressures on the system on peak days, projects are designed to alleviate the pressure constraints.

II. Present Drivers:

There are two primary drivers for the increased need for pressure improvement projects within the AGL system. They are system demand growth and constraints on the major pipelines feeding into the regional systems.

System Demand Growth - The increase in new customers as outlined in section 5.9 above, as well as increased use of natural gas by commercial and industrial customers based on lower cost and/or lower emissions than other traditional fuel sources, continues to strain local pressure systems. The need for a pressure improvement project may be the result of a single large commercial load, a large commercial or residential development being added to a system, or multiple smaller loads being added over time. A prime example of the latter is the current 2021-2022 planned project just north of Midtown Atlanta. This area, circled in the inset map, has seen steady increases in loads due to infill, replacement of smaller homes with larger ones, and increased commercial development to serve the additional residents in and around the Buckhead area. Customers in this area are supplied by a large 45 psi gas system that is fed at multiple points along the edges of the circle from higher pressure pipelines. As gas demand has slowly increased in this area over multiple years, system pressures on the coldest days have continued to drop to where it can require manual bypassing of some pressure regulating facilities to maintain minimum pressures to serve the customers. The only viable solution to this issue is a high-pressure pipeline into the middle of this area including a significant length of pipeline in the highly congested Piedmont Rd corridor. This project alone is estimated to cost more than double the $10 million dollar budget normally allocated to all pressure improvements within the AGL system each year. For this reason, this project named the “Peachtree PRIM” is now being worked as a System



Reinforcement project and AGL has proposed that it be included under the proposed SRR portion of the i-CDP. This project also illustrates how pressure improvement projects and system reinforcement projects are similar. Both types of projects are required to meet customers' needs. The distinctions between the two project types are the scale, scope, and duration of the projects.

Major Pipeline Constraints – As outlined in section 5.10 on System Reinforcement, many of AGL's primary supply pipelines are already constrained where they are near or even below minimum pressures on high-demand days. When these primary supply pipelines are operating at or below minimums, the connections to the regional systems start out constrained and get worse between there and the customers. This may limit the system's ability to absorb additional growth without the upsizing of existing pipelines or adding new system connections. With so many of the larger primary supply pipelines already constrained, AGL will continue to require increased spending on pressure improvements to continue to serve growth on the system.

III. Funding Requirements:

Table 23: Pressure Improvements Budget[13]

Pressure Improvements *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	11.3	**11.5**	**14.5**	**24.2**	**19.4**	**19.9**	**10.6**	**10.8**	**11.0**	**11.2**	**11.5**	**11.7**	**11.9**	**12.1**	**12.4**
Pressure Improvement (PRIM) - GRAM	*11.3*	*11.5*	*13.2*	*8.2*	*8.4*	*10.4*	*10.6*	*10.8*	*11.0*	*11.2*	*11.5*	*11.7*	*11.9*	*12.1*	*12.4*
Pressure Improvement (PRIM) - SRR	*0.0*	*0.0*	*1.2*	*16.0*	*11.0*	*9.5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

5.15. Renewals

I. Introduction:

The Renewals budget includes multiple different project types all associated with replacement and capital repairs of existing facilities. The primary project types included in the Renewal budget are:

- General Renewals
- Posi-Hold Installation Remediations
- Exposed Mains

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[13] See fn 4.

- Emergency Districts
- RCVs
- Partition Valve Remediation

Some of these items are budgeted based on run-rates from previous years to address safety, compliance, and system integrity issues as they arise. Others, such as the Posi-Hold installation remediations, are program specific with known scopes and in many cases known durations.

II. Present Drivers:

Although all Renewal work is generally associated with replacement or capitalized repair of existing facilities, the drivers behind the work can vary. Included below are details for each of the major Renewal work types:

- **General Renewals** – This is the unplanned work each year that must be done due to issues identified on the system. Examples include pipeline replacements due to areas of localized corrosion on steel pipelines, damages, and segments of pipelines with multiple leaks identified through means other than DIMP. This work is generally unplanned and is driven by issues identified in the field by Company or contractor personnel. Historical spending in this area is approximately $5 million per year.
- **Posi-Hold Installation Remediations** – The Company made a five-year commitment to the Commission's Safety Staff to replace or remediate approximately 450 Posi-Hold coupling installations operating at 150 psi or greater and in certain end thrust configurations. This commitment was made in response to a Letter of Concern received from Staff after the failure of several of these fitting installations (Inspection Report No. JL17-001, Docket #37024). The Company is on track to meet its July 1, 2022 commitment with planned investment of $10 million in 2021 and $5.7 million in early 2022.
- **Exposed Mains** – The Company identifies and remediates sections of buried mains each year that may become exposed due to natural causes such as general erosion, creek and riverbank failures and changes, floods, etc. In many cases, it is less costly to remediate the environment around the pipeline than it is to replace the pipeline itself. This is generally done with concrete revetment mats as shown in the picture, courtesy of www.Submar.com/products.

Budgeting of $1 million per year is based on historical investment to remediate these issues as they are identified in the field generally through right-of-way inspections, leak surveys, or other maintenance activities or after major flooding events.

- **Emergency Districts** – This investment is necessary to maintain the ability to shut off gas to specific areas or key facilities in the event of a major system problem, natural disaster, or other unforeseen issue. As systems grow or are connected to other systems for back feeds or pressure improvements, these emergency districts are affected. This may require the installation of additional valves at key points in the system to maintain customer count maximums per district or other strategic limiting factors. The Company routinely spends approximately $0.5 million per year reviewing, refining, and maintaining these districts. This investment has been increased to approximately $0.85 million annually through 2024 as a part of a Company initiative to reduce the size of these districts, add special districts around key facilities where appropriate, and create functionality in the Company's GIS system to be able to identify these districts more quickly in the event of an emergency. At the time of the development of this document in early 2021, there is a current pipeline safety NOPR from Staff, which includes proposed additional requirements concerning valve inspection programs and the associated districts. While a full evaluation has not been completed as to the potential impacts of these proposed new rules, the current NOPR will likely require increased investment in this area.
- **Remote-Controlled Valves** ("RCVs")– In response to the 2010 pipeline rupture in San Bruno, CA as well as several other incidents, in 2011, Congress directed PHMSA to issue new regulations requiring the use of automatic shut-off valves or RCVs on newly constructed or replaced transmission pipelines where it is economically, technically, and operationally feasible. This congressional mandate was in response to concerns over the amount of time it takes to shut down pipelines during incidents. There is a current PHMSA Notice of Proposed Rulemaking concerning the installation requirements of ASVs and RCVs and the related identification and response times associated with reacting to issues on transmission pipelines. While current rulemaking is primarily focused on requiring ASVs/RCVs on new or substantially replaced transmission pipelines, it is expected that there will also be related requirements for existing pipelines based on new provisions in the PIPES Act of 2020. The Company has already begun installing valves with remote controls or remote-control capabilities on new transmission pipeline installations and has proposed $0.4 million in 2021 to continue the installation of remote controls on already identified highest priority valves. This budget is proposed to increase annually by approximately $1

million per year and then maintain approximately $4 million investment in this area per year for 2025-2031. In addition to the pipeline safety benefits, this increased investment may also provide an environmental benefit associated with reduced emissions from third party excavation damages. Depending on the final timing and content of the proposed PHMSA rule concerning RCV's as well as any additional requirements driven by the PIPES Act of 2020, the budget in this area may have to be adjusted in the future to maintain compliance.

- **Partition Valve Remediation** – There are approximately 117 valves currently within the AGL system that serve as a single separation point between different pressure systems. These valves may separate systems with differing pressures of as low as 15 psi or as high as hundreds of pounds of pressure and may be the result of previous construction, system pressure changes, pressure regulating facility removals or replacements, or strategic installations to allow for emergency back feeds. The Company has identified these valves as risks due to the chance of potential over-pressurization of the downstream systems should the valve leak or be inadvertently operated. The Company began the targeted removal or remediation of these valves in 2020 with the intention that all the valves will be addressed over a five to seven-year period to increase safety while limiting the effect this program has on rates. The Partition Valve remediation work is being completed as a part of the General Renewals budget line shown below.

Table 24: Renewals Budget

Renewals (total) *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	16.2	**19.5**	**17.6**	**23.3**	**17.7**	**13.4**	**9.3**	**10.3**	**10.7**	**11.0**	**11.2**	**11.4**	**11.6**	**11.9**	**12.1**
General Renewals	*12.6*	*11.2*	*7.0*	*11.5*	*5.4*	*5.5*	*5.4*	*5.4*	*5.1*	*5.2*	*5.3*	*5.4*	*5.5*	*5.6*	*5.7*
Posi-Hold Installation	*3.6*	*8.3*	*10.6*	*10.0*	*10.0*	*5.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Remote-Controlled Valves	*0.0*	*0.0*	*0.1*	*0.0*	*0.4*	*1.0*	*2.0*	*3.0*	*4.1*	*4.2*	*4.2*	*4.3*	*4.4*	*4.5*	*4.6*
Emergency Districts	*Note: Projects are within the General Renewals budget line*			*0.9*	*0.9*	*0.8*	*0.8*	*0.8*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*0.6*
Exposed Mains				*1.0*	*1.0*	*1.0*	*1.0*	*1.1*	*1.1*	*1.1*	*1.1*	*1.1*	*1.2*	*1.2*	*1.2*

5.16. Regulator Stations

I. Introduction:

AGL has approximately 4,700 pressure regulating facilities from tap stations that include pipeline heaters and odorization equipment to small district stations that may feed a neighborhood or commercial development. Due to obsolescence and identified needs, AGL began increasing capital investment in the replacement of these key facilities in 2017 as shown in the table below.

Table 25: Regulator Station Investments

Regulator Station Investment ($ millions)							
2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
6.4	1.9	4.8	11.5	13.6	13.2	15.2	27.7

In the Fall of 2018, 50 miles of pipeline were over-pressurized in Merrimack Valley, Massachusetts when a regulator station was improperly retired. This resulted in one fatality, 28 injuries, multiple house fires, and the loss of service for more than 8,600 customers for three months. More than 100 buildings were destroyed, and many more structures were damaged. The local utility paid $80 million in a settlement with the three communities, $143 million in a court-approved class action settlement in which more than 175,000 people were eligible to receive compensation, and a $56 million-dollar criminal fine. Numerous individual personal injury claims and individual property damage claims were resolved for amounts estimated to be greater than an additional $1 billion. This incident prompted the review of regulator station configurations for utilities across the entire United States, including at AGL.

In the months following this incident, guidance was issued from multiple agencies including the National Transportation Safety Board ("NTSB") and the Pipeline Safety Unit of the GPSC around actions that should be taken concerning these facilities to help ensure that another event such as happened in Merrimack Valley would not happen again. In addition, the American Gas Association and its members, including AGL, developed and released a white paper with additional recommendations.

AGL convened a team to review all this guidance and evaluate its risks in this area. The review indicated that AGL is not likely to have a catastrophic, over-pressurization event identical to the one in Merrimack Valley. The reason for this is because of the Commission's foresight in allowing AGL to replace its low-pressure bare steel and cast-iron pipelines. Nonetheless, over-pressurization is possible at some individual regulator stations and many of the recommendations from the various agencies and industry groups also apply to elevated pressure stations and related facilities.

II. Present Drivers:

As outlined above, the ongoing and additional acceleration of investment in these facilities is to address known issues such as age and obsolescence as well as to identify and address any additional unknown risks based on federal, industry, and regulatory recommendations stemming from the Merrimack Valley incident.

The Company has three primary initiatives ongoing to immediately begin addressing already identified risks, quantify some additional risks, and to do a full multi-year review of all stations to allow for a comprehensive DIMP type plan to be used to prioritize all station work in the future.

The first initiative was an assessment of potential risks, based off key recommendations stemming from the Merrimack Valley incident, which included industry compiled guidance from the American Gas Association ("Attachment 5.16 -Leading Practices to Prevent Over-Pressurization Final") and directly from the Commission ("Attachment 5.16-Memo_To_Operators_101518_MThebert.pdf"). These assessments have been completed and the following multi-year programs have begun to address these key risks:

- **Installation of Strainers on all 2" and Larger Regulator Stations** – Strainers are being added to these stations to prevent debris in the gas stream from causing regulator failures. All new 2" and larger stations have been installed for multiple years with strainers or other similar protection but there are a significant number of these older stations in the system that do not have this protection. The Company began a 10-year initiative to add strainers to these facilities to increase safety while balancing the impacts to rates by spreading the work over multiple years.
- **Redundant Overpressure Protection at Tap Stations** – The Company has 18 tap stations across its system where the primary overpressure protection (OPP) for the pressure reduction from interstate pipeline levels is on the supplier side. While this protection is properly maintained by the suppliers within all regulations and AGL employees verify that this equipment is being properly maintained, the Company has begun an initiative to install redundant OPP on its side at these facilities to better control the protection of the downstream system and its customers. This initiative began in 2020 with stations in Bremen and Bowden, GA currently being retrofitted with additional OPP and is anticipated to continue through 2024.

- **Kerotest Valve Replacements** – Older 2" x 1.25" Kerotest valves installed within primarily below-ground stations have known dissimilar metal driven (galvanic) corrosion issues with the primary bolts on the valve. Over time, some of these bolts have failed causing significant safety risks for Company personnel maintaining them. While AGL is in the process of completing field verifications to accurately quantify the number of these at risk valves within its system, it is estimated that there are over 2,000 of these valves requiring an estimated five to seven year targeted program to remediate fully.

- **Fire Valves** – The Company has identified a significant number of stations where isolation valves are not easily accessible or may be closer to the station than desired to use them more safely in the event of a station emergency. This has also been an identified area of concern by Commission Inspectors on recent audits and is part of a recent NOPR from Staff. All new stations are now being designed with both inlet and outlet valves that are 25 feet away where feasible. For existing regulator stations, the Company has begun a targeted program to review and remediate issues with existing stations which will be further refined once the field reviews outlined below are completed. While AGL has significantly increased its investment in this area, the proposed rules as written could require even further acceleration of this investment to achieve compliance. Until the final regulations and timelines are known and then each station is reviewed against the new requirements, AGL cannot accurately quantify the potential impacts of this NOPR but it is possible that the proposed rules will require a revision to the i-CDP filing.

The second initiative is a targeted interim review of all stations by Company System Operations personnel while they complete their annual inspections of each station in 2020 and the first quarter of 2021. This effort is focused on better identifying and quantifying many of the issues outlined above, as well as identifying other areas of concern, such as needle valves on sense lines that may be blocked by debris leading to improper regulator operation. As this information continues to come in, it has been used to help prioritize station replacements in 2020 and 2021 and will be used to refine the programs above.

The final initiative, called the Regulator Station Review Program (RSRP), is a detailed records and field review of all AGL pressure regulating stations. This program is ongoing with an anticipated initial completion in 2022. These inspections will include the following:

- Conducting detailed reviews of all current station records
- Conducting field reviews of each station targeting recommended items resulting from industry and regulatory guidance from the Merrimack Valley incident as well as other related Company initiatives.
- Updating of any existing drawings or other system information as needed
- Creating additional flow diagrams and detailed station features lists not currently available today for most stations
- Creating a station health scorecard for each station.

The station health scorecard and this other information will be used to prioritize future station upgrade and replacement work using a DIMP like risk-based approach.

III. Funding Requirements:

Table 26: Regulator Stations

Regulator Stations *($ millions)*	**2018**	**2019**	**2020**	**2021 (GRAM)**	**2021 (Bud)**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	13.6	**13.2**	**15.2**	**27.7**	**27.7**	**29.0**	**32.5**	**32.0**	**27.3**	**27.8**	**28.4**	**28.9**	**29.5**	**25.0**	**25.0**
Regulator Station, Heaters, & Odorization	*13.6*	*12.5*	*12.5*	*22.2*	*22.2*	*25.0*	*30.0*	*32.0*	*27.3*	*27.8*	*28.4*	*28.9*	*29.5*	*25.0*	*25.0*
RSRP Program	*0.0*	*0.6*	*2.8*	*5.5*	*5.5*	*4.0*	*2.5*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

5.17. Removals and Inactive Services

I. Introduction:

The Removals budget line primarily contains anticipated retirement costs associated with many of the other capital support categories including DIMP, DOT, Renewals, and Pressure Improvements.

The Removals-Inactive Services budget is for the targeted retirement of existing active gas services which are being maintained by the Company, but where there is no active customer currently using natural gas.

II. Present Drivers:

Removal spending is primarily driven by investments in the other budget categories as indicated above. There are also sporadic retirement specific projects associated with the retirement of existing mains. Examples include retiring facilities that no longer have the potential to serve customers due to redevelopment, DOT realignments, etc.

In certain situations, there may be an existing service with no opportunity for future gas use at that location. In those situations, the inactive service is at a higher risk of excavation and/or demolition damage since the excavator or building demolisher may assume that there are no active gas facilities on site.

The risks associated with these inactive services has also been identified by the Commission's Pipeline Safety Staff and proposed new requirements concerning inactive services are included in the current pipeline safety NOPR. AGL continues to budget approximately $2 million per year with a small escalator for inflation to address its highest risk inactive services. While the final Commission rules concerning these facilities are not currently known at the time of the development of this document in early 2021, it is likely that investment in this area may need to significantly increase based on the currently proposed language.

III. Funding Requirements:

Table 27: Retirement and Removal of Inactive Services Budget

Retirements (Removals) *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	14.0	**14.7**	**15.0**	**16.1**	**15.0**	**15.6**	**16.6**	**19.7**	**19.7**	**19.7**	**19.8**	**19.8**	**20.3**	**20.3**	**20.3**
Support Project Related Removals	*12.6*	*12.7*	*14.5*	*14.0*	*12.9*	*13.5*	*14.5*	*17.5*	*17.5*	*17.5*	*17.5*	*17.5*	*18.0*	*18.0*	*18.0*
Inactive Service Removals	*1.4*	*2.0*	*0.5*	*2.1*	*2.1*	*2.1*	*2.1*	*2.2*	*2.2*	*2.2*	*2.3*	*2.3*	*2.3*	*2.3*	*2.3*

The Company has budgeted the above removal dollars by year with adjustments associated with changes in proposed spending in the related work categories.

For inactive services, the Company has allocated approximately $2 million dollars annually for the targeted retirements of the facilities and has budgeted to continue this level of investment until more is known around the potential additional requirements stemming from the Commission's current NOPR.

5.18. Maximum Allowable Operating Pressure

I. Introduction:

MAOP refers to the maximum allowable operating pressure, which for each pipeline is the highest pressure at which the Company is allowed to operate.

Following the 2010 gas transmission pipeline explosion in San Bruno, California, Congress mandated that the PHMSA establish regulations requiring pipeline operators to reconfirm the MAOP on each of their existing transmission pipelines that operate in the suburban and urban areas of the country. The PHMSA updates requiring MAOP validation went into effect on July 1, 2020.

II. Present Drivers:

The PHMSA regulation requires "traceable, verifiable and complete" records, above and beyond historic requirements. AGL will need to comply with the new requirements to continue operating its transmission pipelines at their current MAOPs. The regulations apply to all transmission pipelines in suburban and urban areas, even those installed prior to implementation of the initial minimum pipeline safety standards in 1971. The Company's approach to MAOP reconfirmation is safer than the minimum federal requirement, because the Company is evaluating entire transmission pipelines, not just those segments within suburban or urban areas. AGL's approach is not limited to areas where an incident could damage higher populated areas, but rather AGL's approach acknowledges that all Georgians, rural and urban, should have safe natural gas facilities. Moreover, even if an incident in a rural location may cause fewer damages, the service disruption would have far-reaching consequences for all communities served by the transmission pipeline.

Included within the MAOP project is funding to modify pipelines to allow the use of internal inspection tools, also known as smart pigs. Currently, AGL uses all three assessment methods allowed by federal regulation (49 CFR 192.921*):* (a) internal inspection tools, also known as smart pigs, (b) pressure testing, and (c) direct assessment. The Company is required to assess its transmission pipelines located in High Consequence Areas.

AGL uses smart pigs to assess about 40% of the miles of pipe within High Consequence Areas. This is AGL's preferred method of assessment. AGL uses direct assessment for about 58% of its High Consequence Area mileage. The remaining 2% of the High Consequence Area mileage is assessed using the pressure testing method. There are a number of reasons why a pipeline may not be "piggable" such as: certain in-line fittings, sharp bends in the pipe, valves with openings smaller than the pipe diameter, changing pipe diameter, lack of launchers and receivers for the smart pigs to enter and exit the pipeline, and insufficient pressure / flow used to move the in-line inspection ("ILI") tool within the pipeline. To make an existing pipeline capable of accommodating a smart pig, or "piggable," AGL must address each of the areas listed above.

The Company prefers to assess its pipelines using smart pigging because both PHMSA and NTSB have expressed a preference for this method as it provides more data for analysis, which leads to better decisions and further enhances pipeline safety.

III. Funding Requirements:

For each AGL transmission pipeline lacking traceable, verifiable, and complete records, the Company must choose from several alternatives to meet the new standard. Options include but are not limited to: taking the pipeline out of service and pressure testing it to reconfirm the MAOP, abandoning the pipeline, lowering the MAOP of the existing pipeline, or performing extensive in-service material testing for characteristics such as pipe strength or wall thickness. In most instances, if AGL were to lower MAOP or abandon an existing pipeline, AGL must then construct a new replacement pipeline to restore the lost system capacity.

The Company's initial estimate for the remaining cost of MAOP reconfirmation is approximately $700 million. The new regulations will allow pipeline operators up to 15 years to complete this process. As the Company continues to investigate, it learns more about the conditions that need to be addressed, and AGL can better refine the initial estimate.

Currently, the Company has created the Dig Program to administer the MAOP validation work as well as coordinating the TIMP work to gain the synergies of these two programs. The 10-year outlook is shown below and is inclusive of MAOP and TIMP and details the funding requested for modifying pipelines for smart pigging. If these measures are not funded at the levels shown below, AGL could be put in a position where it must forego spending in other areas to comply with the new regulations, which could pose additional risk elsewhere.

5.19. Transmission Integrity Management Program (TIMP)

I. Introduction:

AGL is required by federal regulations (49 CFR 192, Subpart O) to assess its transmission pipelines as part of its Transmission Integrity Management Program (TIMP).

AGL is required to utilize one or more of the following assessment methods to ensure the operational integrity of its transmission lines: (a) internal inspection tools, also known as smart pigging, (b) pressure testing, and (c) excavation and in situ direct examination, (d) guided wave ultrasonic testing (GWUT), and (e) direct assessment, or (f) other technology.

AGL has been assessing its transmission pipelines since the implementation of the Gas Transmission Pipeline Integrity Management regulations in 2003. Additional gas transmission pipeline integrity management regulations were implemented by PHMSA in 2019.

II. Present Drivers:

AGL maintains an assessment schedule for its transmission pipelines to ensure compliance with the regulations. As such, it must be included with the 10-year plan.

III. Future Drivers:

In 2016, the PHMSA published a Notice of Proposed Rulemaking adding MAOP reconfirmation and materials verification requirements and expanding TIMP and Corrosion Control requirements.

Through the rulemaking process, the PHMSA split the proposed regulations into parts 1, 2, and 3. The first phase of the new rules were published in October 2019. Expanded TIMP and Corrosion Control requirements (phase 2) are expected in the next phase of the rulemaking which Congress has asked the PHMSA to complete by October 2021. At this time, there is currently no schedule for the release of phase 3.

IV. Funding Requirements:

As this on-going program is mandated by federal regulations, funding has been included within the 10-year plan to accommodate these needs. As described in Section 5.18, the capital funding for the MAOP Validation and the TIMP work has been combined within the Dig Program. If this program is not funded at the budgeted amounts, AGL could be put in a position where it must forego spending in other areas to comply with these regulations, which could pose additional risk elsewhere.

Table 28: TIMP Budget

TIMP-IVP (total) *($ millions)*	**2018**	**2019**	**2020**	**2021 (GRAM)**	**2021 (Bud)**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	60.5	**83.2**	**106.4**	**63.9**	**60.0**	**61.3**	**90.0**	**91.8**	**116.9**	**96.9**	**96.4**	**95.9**	**95.4**	**93.0**	**99.1**
TIMP-Dig Program	*24.1*	*56.9*	*76.3*	*46.2*	*44.1*	*43.3*	*65.0*	*66.9*	*91.9*	*71.9*	*71.4*	*70.9*	*70.4*	*68.0*	*74.1*
TIMP-ILI Retrofits	*33.9*	*17.5*	*22.2*	*14.4*	*9.4*	*15.0*	*20.0*	*20.0*	*20.0*	*20.0*	*20.0*	*20.0*	*20.0*	*20.0*	*20.0*
TIMP-Other	*2.5*	*8.8*	*7.9*	*3.3*	*6.5*	*3.0*	*5.0*	*5.0*	*5.0*	*5.0*	*5.0*	*5.0*	*5.0*	*5.0*	*5.0*

5.20. Other (PT Meters, Operations, Tools, Other Support)

PT Meters

The Company must periodically test its natural gas meters to verify the meters are working properly. The PT Meter program at AGL complies with Rule 9 of the Tariff and is comprised of two components: Sampling and Remediation.

The Sampling Program uses statistical sampling to determine whether to accept or reject an entire meter group by determining the number of defective meters in a sample from the group. Meters are randomly selected by meter size, type and capacity. Sampling selections do not consider set dates. Meters removed during this process are used in the analysis process.

Remediation is required when the sampling data fails the meter group, and the Company must change/remove the rejected meters. Since the groups are in larger volumes, the meter changes occur over a four-year timeframe.

The quantity of a meter group will have a direct impact on total capital need as the entire group will need to be removed if it fails. The 10-year capital forecast has a more current run rate for testing and failures. There is a risk in any given year that a large meter group may fail requiring increased spending above these run rates.

Vehicular Protection - Bollards

The vehicular protection program is designed to protect Company facilities, mainly meters and services, from accidental damage. The capital budget for this work is based upon the historical rate of facilities identified and associated installations required. The budget reflects a reduction over time due to remediation of current facilities and the up-front installation of needed protection for new services.

Service Renewals

This budget covers miscellaneous capital service replacements completed by Operations personnel on an as needed basis due to damages, leaks, and other issues.

Tools (New Business, Field, and Construction Operations)

The capital tools budget incorporates the equipping of field personnel with the appropriate tools needed to safely complete their work. The capital forecast makes assumptions around the useful life of the various tools and their need for replacement due to failure. AGL is forecasting a levelized run rate spend to reflect purchasing equipment and prioritizing spend for needed items. Additional investments in Tools from 2020 through 2022 above the normal run rate are related to equipping new personnel approved as a part of the 2019 AGL rate case as well as safety related purchases of new emergency tapping equipment for the AGL emergency response (SWAT) team.

Encoder Receiver Transmitters ("ERT") Replacements (Automated Meter Reading devices)

The general life span for an ERT is approximately 20 years. AGL has a run rate budgeted for replacement of failed ERTs. In addition, the Company actively managed an ERT replacement project in 2009-2011 where nearly 1 million devices were replaced, and the capital budget incorporates spreading those replacements over 4 years beginning in 2027 (see below). This increases the budget from ~$5.6M to ~$22M per year starting in 2027.

Table 29: ERT Replacements

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
ERTs Turning 20Yrs Old		21,331	37,059	40,283	33,644	28,773	30,331	34,515	31,070	24,576	221,881	542,575	265,601
Annual Replacement	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Proactive Replacement						20,000	20,000	20,000	225,000	225,000	225,000	225,000	20,000
Total Replacements for Year	20,000	20,000	20,000	20,000	20,000	40,000	40,000	40,000	245,000	245,000	245,000	245,000	40,000

The Company is currently reviewing an alternative technology (Automated Metering Infrastructure or AMI) that can send meter reading information via communications towers rather than being read by a van driving down the street. A pilot program is underway at another Southern Company Gas utility utilizing this new technology, and the plans to replace the AGL ERTs may change depending on the results of that pilot program. A cost/benefit analysis and reviews of other developing technologies could also affect the Company's plans to replace the AGL ERTs. Regardless of whether a new technology is chosen, or AGL continues utilizing the existing ERT platform, a large-scale replacement initiative will be required by approximately 2027.

The tables below outline the current and proposed funding requirements for each of the Operations Support subcategories listed above:

Table 30: PT Meters Budget

PT Meters *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	6.9	**6.8**	**7.1**	**7.0**	**6.8**	**6.8**	**7.0**	**7.2**	**7.4**	**7.6**	**7.8**	**7.9**	**8.1**	**8.1**	**8.1**

Table 31: Operations Budget

Operations (total) *($ millions)*	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	3.9	**3.8**	**3.8**	**3.7**	**5.2**	**5.1**	**5.1**	**21.6**	**21.9**	**21.7**	**21.8**	**8.0**
Bollards	*2.0*	*2.0*	*2.0*	*1.8*	*1.8*	*1.5*	*1.5*	*1.5*	*1.4*	*1.2*	*1.3*	*1.3*
ERT / AMR	*1.2*	*1.2*	*1.2*	*1.2*	*2.7*	*2.9*	*3.0*	*19.5*	*19.8*	*19.8*	*19.8*	*6.0*
Blanket Service Renewals	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*	*0.7*

Table 32: Capitalized Tool Purchases Budget

Capitalized Tool Purchases ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	0.8	1.2	1.6	1.1	1.4	1.7	1.0	1.0	1.1	1.2	1.1	1.2	1.1	1.2	1.2

5.21. Corrosion Control, Shorted Casings, and AC Mitigation

I. Introduction:

Corrosion Control is an important component of pipeline safety for AGL's steel pipelines. Due to the Commission's foresight, AGL has already replaced its bare steel pipelines. In addition to a pipeline's protective coating, the Company applies cathodic protection to the pipelines to prevent corrosion. The requirements for Corrosion Control are defined by federal regulation (49 CFR 192, Subpart I). This subpart defines the requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion. Additionally, this subpart requires mitigation of stray currents that can lead to external corrosion. As such, AGL has an established Corrosion Control program that addresses these code requirements.

II. Present Drivers:

Within the current Corrosion Control capital plan, there are three distinct areas: 1) installation, inspection, and replacement of cathodic protection measures and coatings, 2) mitigation of stray current on pipelines, inclusive of AC mitigation measures, and 3) the shorted casing mitigation program. Each of these areas are required to comply with the existing federal regulation. Also, the shorted casing program reflects a commitment by AGL to the Commission Safety Staff.

III. Future Drivers:

In 2016, the PHMSA published a Notice of Proposed Rulemaking adding MAOP reconfirmation and materials verification requirements and expanding TIMP and Corrosion Control requirements. Through the rulemaking process, the PHMSA split the proposed regulations into parts 1, 2, and 3. The first phase of the new rules were published in October 2019. Expanded TIMP and Corrosion Control requirements (phase 2) are expected in the next phase of the rulemaking which Congress has asked the PHMSA to complete by October 2021. At this time, there is currently no schedule for the release of phase 3.

IV. Funding Requirements:

As this on-going program is mandated by federal regulation, funding has been included within the 10-year plan to accommodate these needs. The 10-year outlook is shown below. Capital funding for area 1 includes the installation, inspection, and replacement of cathodic protection measures and coatings. Capital funding for area 2 includes mitigation of stray current on pipelines, inclusive of AC mitigation measures. Capital funding for area 3 includes the shorted casing mitigation program, which is an AGL commitment to the GPSC Safety Staff that will be completed in 2025. If these initiatives are not funded as budgeted below, AGL could be put in a position where it must forego spending in other areas to comply with the regulations, which could pose additional risk elsewhere.

Table 33: Corrosion Budget

Corrosion *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	6.6	5.3	6.5	7.6	7.7	6.5	6.4	5.9	5.8	5.9	6.0	6.2	6.3	6.4	6.6

Table 34: AC Mitigation Budget

AC Mitigation *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	0.0	3.0	2.1	7.0	5.0	5.0	6.5	6.5	7.0	9.0	9.0	11.0	12.0	12.0	12.0

Table 35: Shorted Casings Budget

Shorted Casings *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	4.8	9.3	9.1	5.0	4.0	4.0	5.0	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0

5.22. Facilities

I. Introduction

The mission of Facilities Management is to provide safe, reliable, and cost-effective maintenance and repairs of Company facilities, supporting the business requirements of AGL. Facilities Management manages and supports the care and maintenance of 32 buildings at 27 locations across the state of Georgia. Those facilities include one customer care center, six depots, one fleet facility, one storage/weld shop, 17 regional business centers and one training center—for a total of 264,000 square feet.

Capital investments in Company facilities include renovations, reconfigurations, and construction of new buildings as well as replacement of HVAC and other facility systems, repaving of parking lots, replacement of office furniture, and other related items necessary to support Company operations.

II. Present Drivers:

There are multiple key facilities in need of replacement, expansion, or other major renovation to continue to provide the necessary support for operations. Major projects by plan year are listed below:

- The 2022 budget includes construction of the new Gwinnett Regional Business Center—a total renovation of an existing building scheduled for purchase and design in 2021. AGL currently leases an office building and owns a second depot that houses field operations personnel and parts inventory. AGL plans to let the lease expire on the office building and purchase a Georgia Power property, in accordance with affiliate transaction protocols, for use as the consolidated Gwinnett Service Center.
- The 2022 budget also includes completing the build of a new Clayton facility on the Riverdale campus that will house the Regional Business Center, SCADA and Measurement, System Operations, and the Meter Shop. The current Riverdale campus includes the Regional Business Center, SCADA, Measurement, System Operations, the Meter Shop, and the Riverdale LNG facility. The RBC is the location of the training center. SCADA, Measurement, System Operations, and the Meter Shop are currently located at Riverdale LNG.
- AGL is onboarding new employees that require training and continues to train existing personnel. Training activities have increased such that more space is needed to

complete necessary training exercises in a timely manner. It is also likely that LNG facilities will be deemed critical infrastructure by the federal government which could necessitate limiting access by individuals to LNG facilities for security purposes. The new facility will relocate SCADA, Measurement, System Operations, and the Meter Shop from Riverdale LNG to the new facility, thus reducing and limiting the number of individuals that have access to Riverdale LNG.

- Upon a successful 2021 property purchase in Savannah, the 2022 budget also includes construction of a new building to house AGL's Savannah Regional Business Center. This project will wrap up construction in early 2023. The current facility lease expires in 2023, and the current space is undersized for the number of personnel at the location. Further, the current building is not capable of withstanding a major weather event such as a hurricane. The new building will enable critical field operations to be conducted during a major weather event and will provide the additional space necessary to conduct field operations.
- Additionally, the 2022 budget includes the purchase of an existing building in Marietta; and, the renovation of the building is budgeted in 2023. This property will house the Company's Marietta Regional Business Center. Similar to Gwinnett, AGL owns a depot that houses field personnel and inventory and leases an office building. AGL plans to buy a building that will serve to consolidate Marietta field operations into one facility at a single location.
- The Macon Service Center lease expires in 2026. The property is located in an area where a great deal of commercial development is occurring, and the possibility exists that the property owner could opt to sell the property. In the event this happens, AGL is planning to purchase property in 2024 and construct a new Macon Service Center in 2025 and 2026. If the property owner does not opt to sell the property and new lease terms can be agreed upon, AGL could withdraw this proposal in a future i-CDP filing.
- The budgets for years 2027 - 2030 are for typical facility refurbishments.

III. Funding Requirements:

Table 36: Facilities Budget

Facilities ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	12.8	1.5	7.2	22.4	18.6	28.5	14.0	9.0	13.5	8.3	6.0	6.3	6.3	6.5	6.5

5.23. Fleet

I. Introduction:

The mission of Fleet Operations is to provide safe, reliable, and cost-effective transportation and power-operated equipment supporting the business requirements of AGL. Fleet Services manages and supports the complete lifecycle of over 1,250 pieces of transportation and power-operated equipment from acquisition to maintenance and repairs to disposal at locations across the state of Georgia.

II. Present Drivers:

Major drivers of Fleet capital spend include market driven price increases of vehicles, incorporating safety and technology enhancements (collision avoidance, lane departure, telematics) and the incremental increase in vehicle count because of additional Company staffing requirements. Current investments are higher than the normal Fleet run rate spending due to the vehicles necessary for the additional Company resources approved to increase safety and customer service in the 2019 AGL rate case.

III. Funding Requirements:

The table below includes the estimated capital investments necessary to provide Company personnel with vehicles and equipment required to perform their daily activities. While no adjustments have been made to the current forecasted budgets to accommodate any changes in vehicle types, AGL is currently evaluating the potential for increased investment in alternative fuel vehicles and equipment that may require adjustments to these forecasts.

Table 37: Fleet Budget

Fleet *($ millions)*	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	7.9	8.8	13.3	11.4	12.1	8.6	8.2	8.4	8.6	8.7	8.9	9.1	9.3	9.5	9.7

5.24. IT

I. Introduction:

IT capital investments generally consist of base business expenditures and systems work as outlined below:

- Base Business-Equipment- Direct purchases of new replacement laptops, Toughbooks, and related computer equipment for personnel to perform their daily duties.
- Base Business-AGL Specific Systems – Capital system maintenance and upgrades on programs that are specific to AGL operations. The primary AGL specific program is the Georgia Customer Management Application (GCMA). This program is specific to AGL operations and cannot currently be shared with other Southern Company Gas entities due to the inclusion of Natural Gas Marketers.
- Enterprise Asset Management (EAM) system – This new system, as described below, is shared across all of the Southern Company Gas regulated utilities but has been budgeted at the utility level for clarity.

II. Present Drivers:

Baseline spending on new and replacement laptops, ToughBooks, and other related equipment, as well as known specific Georgia Customer Management System (GCMA) enhancements, are the basis for the IT (Base Business) funding and are necessary to support daily operations. Southern Company is in the process of consolidating several IT systems at all of its operating companies specifically related to accounting, human resources, financial planning and budgeting, and supply chain. The consolidation of these IT systems is expected to be complete in January 2022. This consolidation also involves modifications to the GCMA system used exclusively by AGL within the Southern Company enterprise. GCMA is one of the Marketer interfaces with AGL used to share customer information. The budget includes estimated costs necessary to consolidate the above IT systems and enable interface of GCMA with the consolidated system.

The Enterprise Asset Management program, or EAM, is a unified and coordinated approach to effectively and safely manage all asset data related to the flow of gas within the Southern Company Gas enterprise. The primary purpose of the EAM system is to improve pipeline safety, enhance operational efficiency, and to optimize costs with reliability and resiliency. These capabilities will be enabled by a core EAM solution with asset and work management tightly integrated with GIS, document management, and design solutions that will provide traceable, verifiable, complete, and accurate data. EAM will complement the IT system consolidation that merges operating company financials and human resources functions by housing specific AGL natural gas asset information and is expected to be completed in 2024.

III. Funding Requirements:

IT-Base Business projected investment levels are shown below.

The development and implementation of the new EAM system will be a multi-year project in support of all Southern Company Gas' regulated utilities. The funding requirements listed below represent the anticipated allocation of the program costs to AGL based on customer count.

Table 38: IT Budget

IT *($ millions)*	**2018**	**2019**	**2020**	**2021 (GRAM)**	**2021 (Bud)**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
	6.7	**6.2**	**16.8**	**1.0**	**7.8**	**16.4**	**17.8**	**3.7**	**3.0**	**3.0**	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**
IT-IT (Base Business)	*6.7*	*6.2*	*16.8*	*1.0*	*1.9*	*3.5*	*2.0*	*3.0*	*3.0*	*3.0*	*1.3*	*1.3*	*1.3*	*1.3*	*1.3*
IT-IT (EAM)	*0.0*	*0.0*	*0.0*	*0.0*	*5.9*	*13.0*	*15.8*	*0.7*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

5.25. Overheads and AFUDC

I. Introduction:

The cost of resources and funds required to support capital projects at AGL is captured in Overheads and Allowance for Funds Used During Construction (AFUDC). Overheads consists of Services Company and AGL specific capitalized expenses necessary to support these projects. This may include but is not limited to Engineering, permitting, land rights, Supply Chain, construction management, inspection, Accounting, and other personnel and expenses associated with these capital projects. AFUDC is intended to recover the cost of funds (debt and equity) used during the construction of these projects.

II. Present Drivers:

Overheads are projected and allocated to the direct capital for projects planned for each year. The allocation is based upon the cost of resources required to support capital projects in relation to the total capital spend on a monthly basis. A 3% rate is generally used to forecast incremental year-over-year increases in overheads. AFUDC is estimated based upon the forecasted CWIP balances related to the expected project in-service dates. Year-over-year changes in the AFUDC budget are related to expected CWIP balances and project completions during each year.

III. Funding Requirements:

Table 39: New Business Budget

New Business-OH & AFUDC ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	8.0	7.1	8.3	7.8	9.5	5.8	5.6	5.7	6.2	6.5	6.4	6.4	6.6	6.9	7.0

Table 40: Overheads, AFUDC, Allocations Budget

Rate Base Overheads, AFUDC, and Allocations ($ millions)	2018	2019	2020	2021 (GRAM)	2021 (Bud)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	25.9	25.9	38.9	31.0	35.5	42.9	47.2	48.2	46.1	44.3	45.6	46.8	47.7	49.1	49.6

5.26. Incremental Operation & Maintenance (O&M) Expenses Directly Related to New Capital Projects

While the majority of the proposed capital investments as outlined within Chapter 5 of this document will be supported by existing resources, there are some new incremental expense requirements including:

1. Cherokee LNG Plant Expansion – The doubling of the Cherokee LNG plant's capacity and sendout capabilities will require additional annual investment of approximately $1.4 million to operate and maintain the expanded facility. This additional O&M will include two additional technicians and one additional maintenance specialist as well as additional expenses related to LNG storage and maintenance of the facility.
2. Additional Reporting for i-CDP – The i-CDP stipulation of the Staff and AGL establishing a long-range comprehensive planning process requires a significant amount of additional reporting and analysis. This includes quarterly, annual, and project/program specific reporting as well as analysis and summaries for changes within and across budget categories. Although there are still unknowns around future reporting and requests, it is

estimated that an additional analyst resource will be needed to provide this increased level of reporting. Since this resource will be dedicated to capital projects, the majority of the costs for this individual will be allocated to capital with only approximately 10% allocated to expense.

Funding Requirements:

Table 41: Cherokee LNG Expansion Incremental O&M Budget

Cherokee LNG Expansion ($ millions)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	0	0	0	0	0	0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4

CHAPTER 6. BEST PRACTICES PROGRAMS

6.1. Introduction

The following section addresses “Best Practices” which the Company categorizes as ongoing Operations and Maintenance related initiatives at AGL that improve the safety, quality, and/or reliability of the AGL pipeline system. They are programs established by the Company to identify risks and address existing identified risks or future potential risks associated with the AGL system or records. The programs vary greatly in the areas that they impact, but have one thing in common, which is that in all cases will improve the safety, quality, and/or reliability.

6.2. Celcon Caps

I. Introduction:

In 1984, the Company started transitioning away from the use of Dupont Aldyl-A plastic for mains and services and started using a medium density Polyethylene (PE) plastic manufactured by Plexco. This transition was made due to the improved material characteristics of the Plexco material as compared to the Dupont Aldyl-A.

While the new pipelines were made entirely of PE, the new service tees that were used to run service lines off of the mains were constructed of PE with the exception of the cap that was threaded onto the top of the tee.

These service tee caps were made of a material called Celcon which was a polyacetal plastic which was an early plastic resin. These caps were installed by the Company between 1984 and 1995. The caps are prone to stress cracking and therefore leakage rates are higher on gas systems with Celcon caps.

II. Present Drivers:

At AGL continues to experience a number of these cracked caps every year and the leakage rate on the plastic facilities installed between 1984 and 1995 is higher than on more current plastics. The cracked caps most commonly result in non-hazardous leaks at the service tee, which is typically located out at the street. However, in areas where the service tee is installed closer to the building (apartment complexes and condos), these leaks are potentially hazardous.

Therefore, several years ago, the Company proactively began to replace service tee caps in those types of short service situations described above where the original pipelines were installed between 1984 and 1995. Since 2016, the Company has replaced about 1,000 of the estimated 10,000 of these caps at apartment complexes and other short service line situations identified so far. Currently, the Company is spending approximately $1.1 million dollars per year replacing these caps. At that rate, the Company expects to replace all higher risk Celcon caps by 2032, barring any other safety projects taking higher priority.

If additional caps are subsequently identified, this could extend the period of work or increase the annual spend associated with the program.

III. Funding Requirements:

Table 42: Celcon Caps Budget

Celcon Caps ($ millions)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	.2	.2	.8	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1

6.3. Cross-bores

I. Introduction

A cross-bore occurs when a gas pipeline is installed through an existing, underground sanitary sewer or storm sewer pipe. A cross-bore can be a serious safety hazard if the sewer becomes blocked because of the gas line inside the sewer pipe. Once a blockage occurs, a sewer employee, plumber or homeowner can damage the gas line if they attempt to clean out the sewer line with a rooter-type, drain-cleaning device without first investigating the cause of the blockage. This can result in a significant natural gas leak into the sewer system, which can quickly accumulate in surrounding homes and businesses and may result in fires and explosions.

II. Present Drivers:

In 2020, AGL investigated and remediated those areas with known cross-bore at a greater pace than in previous years. However, as the 10-year program to eliminate all known cross-bore areas was not completely funded and additional areas with cross-bore have been identified, the Company still has many years to go. 175 cross-bores were identified and remediated in 2020.

A Phase II cross-bore program is anticipated for the future. In addition to the newly identified cross bore areas, AGL is exploring the use of data analytics and artificial intelligence to identify those areas most at risk for cross-bores but that have not had any cross-bores identified yet.

III. Future Drivers:

In the future, if cross-bores are identified in other areas of the AGL system, the cost and duration of this program will increase.

IV. Funding Requirements:

Because of the risk of AGL's pipelines being damaged by drain cleaning equipment, ongoing O&M funding will be required to continue investigating and remediating areas with previously identified cross-bores.

Table 43: Cross-bores Budget

Cross-bores ($ millions)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	3.7	2.3	5.7	6.8	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3	15.3

6.4. Reducing Third Party Excavation Damages

I. Introduction

AGL has implemented a "Watch and Protect" Program to improve pipeline safety by reducing damages from third party excavators. The Watch and Protect Program uses the Company's GIS and locate ticket management system to identify excavation near critical pipeline facilities. Watch and protect personnel are then notified to help ensure that critical facilities are not damaged by:

- Performing a site walkthrough to review the excavation site details;
- Verifying the accuracy of the marks by the initial locator;
- Engaging with the excavator to exchange contact information and coordinate schedules;
- Returning to the site once excavation activity begins around the critical facility to "watch and protect" and ensure that excavation best practices are being used; and
- Intervening as needed to ensure that damages are prevented

II. Present Drivers:

COVID-19 slowed the implementation of the Watch and Protect Program in 2020. Despite the challenges of hiring and training personnel during a global pandemic, AGL hired, trained, and equipped 5 watch and protect personnel and 1 supervisor in 2020. In 2021, AGL will be hiring, training, and equipping 9 additional Watch and Protect personnel.

III. Future Drivers:

As the number of economy-driven excavations increase, AGL plans to ensure that its Watch and Protect Program meets the growing demand. This program, coupled with innovative technology and increased analytics discussed in section 6.4 above, will further reduce third party excavation damages.

IV. Funding Requirements:

Because third party damage is a significant safety risk to AGL's pipelines, ongoing O&M funding will be required to continue and ensure that the Watch and Protect Program reduces third party excavation damages as the demand for locate services increases. AGL plans to grow its Watch and Protect Program to keep delivering on the goals defined above.

Table 44: Reducing Third Party Excavation Damages Budget

Watch & Protect Program ($ millions)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	.1	1.0	1.0	1.0	1.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1

6.5. Improving Data Quality and Accessibility

I. Introduction

AGL has developed a source record validation process, which requires verifying and updating historical asset information within the company's GIS to ensure the data is accurate and complete. It includes scanning historical construction records (as-builts, pressure test charts, bills of materials, etc.), indexing these source records into the EAM system, and updating GIS as needed. Source record validation improves pipeline safety by making accurate records available to field personnel.

II. Present Drivers:

Efforts to access and scan records were adversely affected due to COVID-19; as personnel safety protocols were being developed, additional personnel such as those required for scanning records, were not permitted in AGL facilities. Despite the challenges in 2020, AGL completed scanning at 2 service centers. Currently, AGL is scheduled to complete scanning and indexing source records for the remaining service centers in 2021.

Once scanning and indexing is complete, the records will be stored in the EAM system that allows the scanned images to be searchable using the indexed data fields.

Additionally, AGL will make necessary updates to the GIS, which AGL anticipates will be an on-going task through 2029.

III. Funding Requirements:

Because having accurate records available to field personnel improves pipeline safety, ongoing O&M funding will be required.

Table 45: Improving Data Quality and Accessibility Budget

Source Record Validation ($ millions)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	.4	.04	1.8	1.7	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	-

6.6. Expanding Quality Assurance

I. Introduction

In general terms, Quality Assurance (QA) is the evaluation of work being performed to ensure the desired level of quality. This focus is on both personnel and pipeline safety and it is done by providing an independent internal review of how a company's employees and contractors are performing their work in the field.

II. Present Drivers:

The three existing quality assurance technicians at AGL assess construction work as it is being conducted in the field by the Company's construction contractors to validate that appropriate procedures are being followed. Those positions, however, are limited in scope to construction work.

The Company during its last rate proceeding, proposed the expansion of this group to cover additional areas of work. This expansion was for the addition of one QA Manager and four additional specialists. These bodies were proposed to cover the expansion of QA into the additional areas of operations and maintenance work performed by employees and contractors in the field as well as work performed in customers' homes.

The projected O & M costs of those positions were $440,000 annually. However, those positions have not yet been filled, as the Company did not receive all of the funds it had requested in that proceeding and other programs within the case have taken higher priority so far.

III. Funding Requirements:

Table 46: Quality Assurance Budget

Quality Assurance ($ thousands)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	309	308	307	700	940	940	940	940	940	940	940	940	940	940

6.7. Applying PSMS

I. Introduction

In 2015, the pipeline industry, working together with federal and state pipeline safety regulators and pipeline safety advocates, developed a recommended practice (API RP 1173) on PSMS. This American Petroleum Institute (API) recommended practice is designed specifically for pipeline operators and is very similar in approach to the practices used by the Airline and Nuclear industries.

II. Present Drivers:

PSMS are designed to enhance pipeline safety by applying a “Plan-Do-Check-Act” cycle to how the pipeline operators approach safety. This approach, in general terms, is to determine the steps that need to be taken across operations, complete those steps, periodically review those steps, and make any changes or improvements as necessary following that review. By applying those steps as the Company continues to operate, AGL plans to improve personnel and pipeline safety in a variety of areas around the Company.

The Company is currently in the process of adopting and implementing PSMS. The Company filled the PSMS Manger role in August 2020 and executed a gap analysis of existing operational practices and procedures with external consultants to establish the current level of maturity with API RP 1173 elements. Going forward, the Company is continuing to develop a more comprehensive PSMS plan, which will document the processes and capabilities of the Company to execute the elements of API RP 1173. The Company is currently developing a roadmap and set of prioritized initiatives to improve PSMS program maturity and adoption across the organization. This will be an iterative process moving forward as the Company implements its PSMS program, completes initiatives, measures performance, and undertakes subsequent initiatives. The Company also anticipates filling an analyst position in CY 2022 in order to support the PSMS program and processes.

III. Funding Requirements:

Table 47: PSMS Budget

Pipeline Safety Management System ($ thousands)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	0	0	292	110	113	416	116	116	416	116	116	416	116	116

6.8. Future Best Practices

In late December 2020, Congress passed a new Pipeline Safety Reauthorization Bill. This reauthorization was initially scheduled to be passed in September 2019 when the previous reauthorization expired, however, it was delayed for 16 months due to significant differences of thought among the Members of Congress on where pipeline safety should be focused in the future.

Historically, pipeline safety has been a non-partisan issue and the focus of reauthorization was specifically on preventing pipeline incidents and ensuring the safe operation and maintenance of the nation's pipeline infrastructure. This time, the issues of climate change and methane emissions were raised within the context of pipeline safety, and this expansion of topics delayed the adoption of a reauthorization bill.

The bill signed by the President in December has many directives from Congress for PHMSA and other groups to undertake that will, over the coming years, add to or significantly modify the way the Company operates and maintains its pipeline system. These in many ways are "Best Practices" that will be tied to future pipeline safety regulations.

Below are a few examples of what Congress has directed PHSMA to include in the development of new regulations over the next two years that will affect pipeline operators and future costs:

1. Enhance leak investigation programs using new technology to find leaks
2. Require the repair of non-hazardous leaks that have emissions
3. Enhance emergency response plan communications with first responders, government officials and the public

4. Develop Management of Change (MOC) procedures for work done on pipelines
5. Add additional regulations on over-pressure protection of existing pipeline systems
6. Ensure system pressure control records are traceable, reliable and complete
7. Put in place new construction and operating procedure requirements that reduce the release of natural gas into the atmosphere.

These new regulatory requirements will ultimately require AGL along with other pipeline operators to adopt new technologies, develop new procedures and establish additional programs. Therefore, it is quite possible that these additional programs driven by congressional mandates and ensuing PHMSA regulations could result in additional costs that will have to be borne by the Company and its customers in the future.

6.9. Conclusion on Best Practices

"Best Practices" is not a static concept. It is something that continues to evolve as the experience of AGL and other utilities in the industry matures. There are other best practices that AGL mentions in this Plan that go beyond the bare minimum required by federal regulations. AGL made the decision to implement these "Best Practices" mentioned in the Plan, such as pigs and RCVs. These decisions are part of the Company's ongoing effort to implement what are "Best Practices" for the safety of its customers and the communities that AGL serves, as well getting the best value from investments the Company is making in the natural gas systems in Georgia for current and future generation of customers.

CHAPTER 7. CUSTOMER RETENTION AND GROWTH PROGRAMS

AGL has designed and implemented programs to add customers, prevent attrition of customers at risk of leaving the system, and win and retain multifamily developments. These programs create downward pressure on rates by reducing O&M costs, adding and retaining customers, and avoiding the need to prematurely retire certain infrastructure as a result of customer attrition. The three current AGL customer growth and retention programs described below are: 1) the residential and commercial conversion rebate program; 2) the heat-only to year-round program; and 3) the multifamily incentive program. Awareness will be created for these programs through advertising and outreach. The estimated cost for advertising and outreach efforts is $230K in 2021, with an estimated 2% annual increase.

1. <u>Residential and Commercial Conversion Rebate Program</u>

The residential and commercial conversion rebate program provides incentives to new and existing customers to offset the cost of converting to natural gas equipment from an alternate fuel source. Fuel conversions to natural gas in existing structures present significant costs because adding or modifying gas infrastructure into finished space is difficult with drywall, floors, and ceilings already in place. Incentives encourage these conversions and remove some of the barriers for customers to install more efficient equipment with lower operating costs.

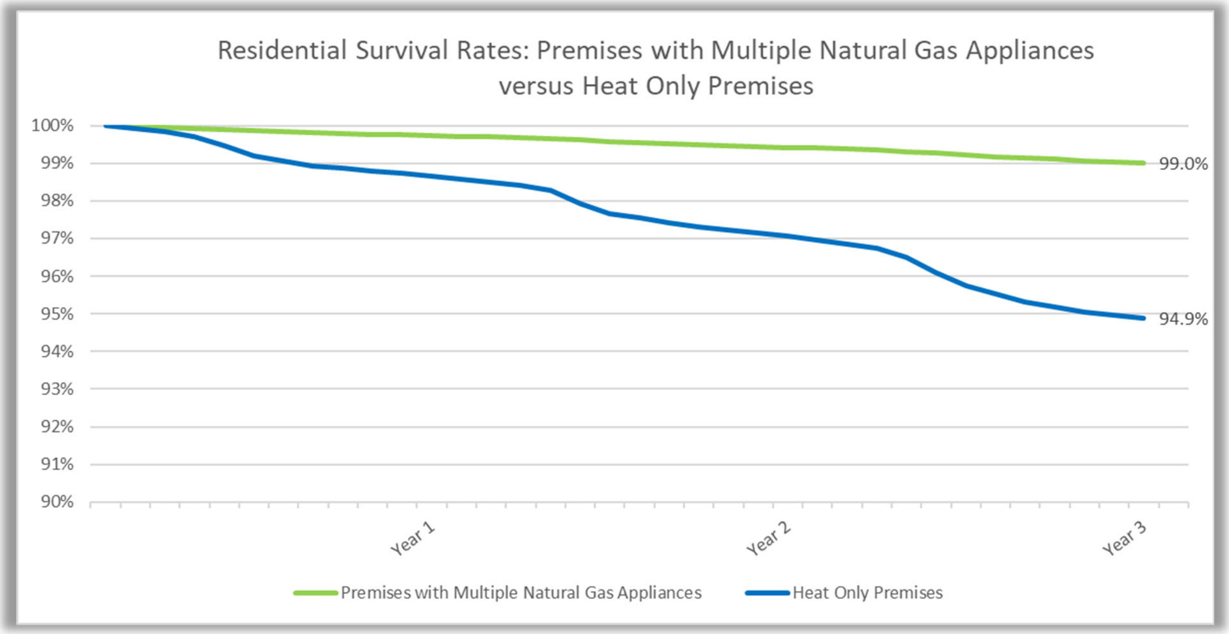
Conversion rebates add new customers to the AGL system, create additional revenue from existing customers, and lower the attrition risk of existing customers. AGL adds, on average, 150 new customers annually by providing conversion rebates. In addition, AGL lowers the attrition risk of an additional 400 customers annually, on average, by offering conversion rebates to existing customers. The budget for rebate payments under this program is expected to be approximately $315,000 in 2021, and AGL anticipates a 5% annual increase in future years. A summary of the current conversion rebate offers available to customers is shown below:

Figure 11: Current Conversion Rebate Offers

2. <u>Heat-Only to Year-Round Program</u>

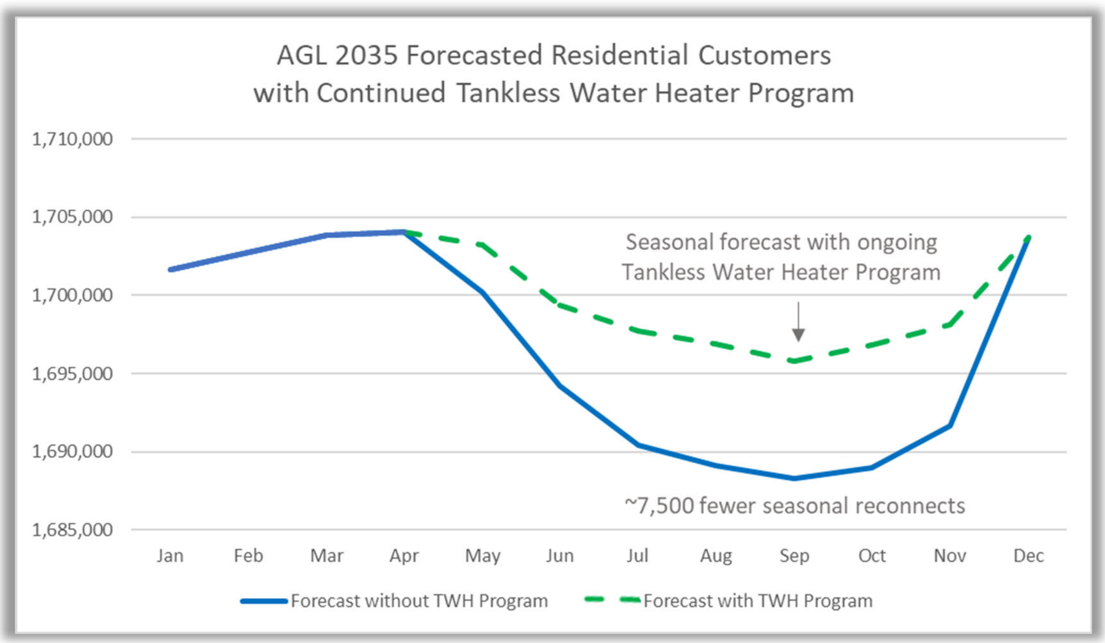
AGL's heat-only to year-round program provides heat-only customers a free tankless water heater if the customers commit to stay on year-round. Compared to customers with multiple natural gas end uses, heat-only customers are believed to have a four to five times higher risk of leaving the system. Therefore, adding a year-round appliance significantly reduces the attrition risk of this group of customers.

Figure 12: Premises with Multiple Natural Gas Appliances Versus Heat Only Premises



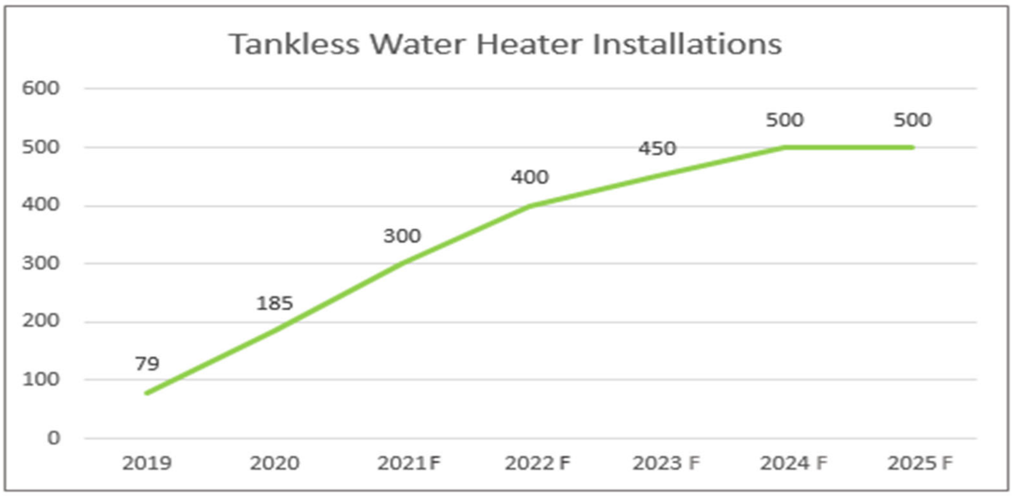
In addition to being high-risk for attrition, heat-only seasonal customers often require at least two visits from AGL each year to deactivate service at the end of the heating season and safely reactivate service at the beginning of the heating season. By converting heat-only seasonal customers to year-round, AGL increases revenue and avoids the turn-off and turn-on service calls.

Figure 13: Forecast for Tankless Water Heater Program



Additionally, by preventing attrition, this program avoids the capital expense required to retire inactive services at premises where a customer has left the system. AGL is offering a "turn-key" water heater installation to heat-only customers in service territories with a higher-than-average attrition risk. Currently the program is running in Savannah, Brunswick, Macon, Athens, Rome, and Augusta with plans to expand it to more service territories. Tankless water heater unit and installation costs are budgeted to be approximately $750,000 in 2021, $1,000,000 in 2022, $1,125,000 in 2023, and $1,250,000 in 2024 as the program is expanded. Recent and forecasted tankless water heater installations are shown in the chart below.

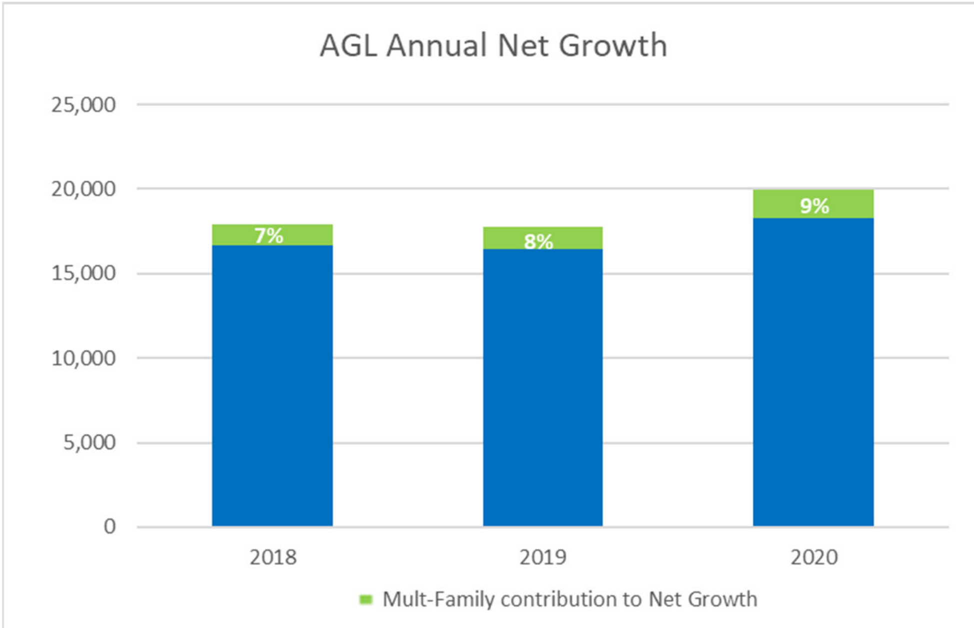
Figure 14: Recent and Forecasted Tankless Water Heater Installations



3. Multifamily Incentive Program

A multifamily development with a master meter under AGL's G-10 rate may have up to 2.5 miles of gas pipe downstream of the meter. Under this rate, the developer handles the cost of furnishing and installing gas pipe and the increased costs associated with properly installing and venting gas equipment compared to all-electric construction. AGL provides incentives to help offset these costs and promote the use of gas appliances in multifamily developments. These incentives have helped AGL serve thousands of apartments and have increased AGL's customer billing unit growth rate by 8% average over the past three years. AGL plans to commit $1.5 million dollars in incentives annually to offset construction costs for developers and secure appliances in multifamily developments. These incentives are amortized over the contract life of 15 years.

Figure 15: Multifamily Contribution to Annual Net Growth



Funding Requirements

Table 48: Customer Growth & Retention Budget

Customer Growth & Retention	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Conversion Rebates												
Conversion Rebate Payouts (5% YOY increase starts in 2022)	239,300	315,000	330,750	347,288	364,652	382,884	402,029	422,130	443,237	465,398	488,668	513,102
Tankless Water Heater Sweepstakes												
Water Heater + Installation Costs	602,026	750,000	1.0m	1.13m	1.25m	1.25m	1.25m	1.25m	1.25m	1.25m	1.25m	1.25m
Multifamily Rebates	1.0m	1.5m	1.5m	1.5m	1.5m	1.5m	1.5m	1.5m	1.5m	1.5m	1.5m	1.5m
Amortized payments	156,164	240,791	340,791	440,791	540,791	640,791	740,791	840,791	940,791	1.0m	1.1m	1.2m
Total Spend	1.0m	1.3m	1.7m	1.9m	2.2m	2.3m	2.4m	2.5m	2.6m	2.8m	2.9m	3.0m
Advertising (2% YOY increase starts in 2022)	206,568	230,000	234,600	239,292	244,078	248,959	253,939	259,017	264,198	269,482	274,871	280,369
Less non-customer funded contributions	-788,246	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000	-700,000
Total Recoverable Spend	415,812	835,791	1.2m	1.5m	1.7m	1.8m	1.9m	2.0m	2.2m	2.3m	2.5m	2.6m

CHAPTER 8. ENVIRONMENTALLY-FOCUSED INITIATIVES

Natural gas has played a critical role in reducing greenhouse gas emissions (GHG) over the last several decades, including in the electricity sector. AGL believes natural gas will continue to play a vital role in meeting climate goals for decades as renewable energy options become more abundant and reliable. Although natural gas is a clean burning fuel, it is a contributor of GHG. As such, policymakers, AGL's customers, and society in general expect, if not soon require, that the natural gas chain from the wellhead to burner tip do its part to reduce and offset its net carbon footprint. Innovation, technology, and new techniques will be required to sustain use of this abundant resource that has kept energy overall energy costs historically low.

Like many energy providers, Southern Company, the parent company of AGL, has set GHG emissions reduction goals across all electric and gas operations. In addition to considering investments to reduce direct and indirect emissions, AGL's parent Company is exploring what are considered to be carbon-neutral forms of gas, such as renewable natural gas ("RNG") and hydrogen. AGL is not proposing any capital investment or pilot projects at the time of this filing as it relates to this Chapter 8; however, AGL desires to inform the Commission that over the next few years it is exploring initiatives such as those set forth below.

During the 10-year planning horizon of this i-CDP planning period, AGL will consider a more structured, integrated approach to reducing its direct and indirect[14] GHG emissions, including CO_2 and methane. The direct emissions initiative builds on many years of AGL working to reduce emissions. For example, AGL has already achieved significant GHG reductions from investments in pipeline and infrastructure replacement. AGL has reduced its annual methane emissions by 60% from 1998 to 2018 by eliminating miles of leak-prone pipe from its system, even as the total mileage increased by 21%. While indirect emissions are not directly related to AGL's utility services, AGL recognizes the importance of improving the environmental footprint of customers' energy uses while continuing to provide safe, efficient, low-cost energy.

[14] "Direct emissions" refers to emissions from sources that are owned or controlled by AGL. "Indirect emissions" refers to emissions that occur at sources owned or controlled by AGL's customers as a result of the customers' use of natural gas.

The major components of the initiative include: (1) direct emissions (primarily methane and CO_2 emissions); (2) indirect emissions (from natural gas customers); and (3) RNG opportunities.

1. Direct Emissions

AGL's direct emissions include fugitive and vented methane from gas operations and CO_2 from operational combustion. According to the U.S. Environmental Protection Agency ("EPA"), methane is an important GHG. Although methane represents considerably less of the total GHG emissions than CO_2, the EPA has determined that its global warming potential is higher than CO_2 and has a series of voluntary programs supporting methane emissions reductions, in addition to regulatory initiatives. In addition to the measures described below to reduce its annual GHG emissions, AGL will evaluate opportunities to offset the remaining emissions with creditable methane and carbon offsets.

a. Methane Emissions

The biggest opportunity to reduce methane emissions will be an expanded leak detection and repair (LDAR) program for gas meters. Under this program, AGL will leverage existing corrosion surveys to check meter sets (meters and regulators at premises) for leaks and repair any identified leaks. This program has potential to significantly reduce methane emissions.

AGL will also evaluate expanding LDAR programs for meter and regulator (M&R) stations and the use of technologies to reduce vented (blowdown) emissions.

AGL will look into the possibility of offsetting the remaining methane emissions with creditable methane and carbon offsets.

b. CO_2 Emissions

AGL will evaluate opportunities to address CO_2 emissions from combustion of gas-fired equipment used in operations by evaluating options like fueling combustion equipment with carbon-neutral RNG, offsetting of emissions, or replacing gas-fired compressors with electric compressors, which would mitigate direct emissions as the electric grid decarbonizes.

Vehicle fleet[15] emissions are another source of direct CO_2 emissions. AGL will evaluate opportunities to reduce these emissions through:

- Transportation demand management to reduce vehicle usage.
- Use of compressed RNG, electric and plug-hybrid, hydrogen fuel cell, and biodiesel vehicles, including off-road equipment.

2. Indirect Emissions

Emissions from customers' use of gas ("indirect emissions") are more significant than AGL's direct emissions. Promoting energy efficient building and use of highly efficient gas appliances, like the natural gas-driven heat pump, has the potential to reduce customers' costs, gas consumption, and emissions. AGL has the experience and expertise to help customers deploy higher efficiency building and appliance technology.

3. Renewable Gas Opportunities

Although there are no RNG capital projects known at this time to include within this i-CDP filing, the Company is actively preparing for additional RNG opportunities or requirements.

RNG may be considered carbon neutral (and in some circumstances, carbon negative) and a sustainable alternative to supplement geologic natural gas. RNG can be produced from abundant amounts of organic waste from sources such as farms, wastewater plants, and landfills. Instead of allowing methane to escape into the atmosphere from decomposing organic waste, the released gases can be used to produce methane-rich biogas. There are applications in which biogas can be used as a valuable energy source. Alternatively, biogas can undergo additional processes to clean and condition the gas to meet pipeline quality requirements. RNG that has been through these additional processes is interchangeable with conventional, geologic natural gas. Renewable gas facilities provide a suite of benefits, including cross-sector emission reductions, beneficial use of waste methane (with RNG), resiliency and fuel diversity through additional locally sourced

[15] Fleet capital costs are identified in other chapters of the Plan. Only incremental capital costs associated with CO_2 emission reductions would have been provided for in the subcategory in this Chapter 8. As stated previously, AGL has not included any capital costs for this subcategory in this i-CDP.

supply options, local economic investment, local jobs, increased flexibility, and utilization of the natural gas system.

RNG facilities can offer many benefits, including two distinct emission reduction benefits. First, because RNG is created from renewable or biogenic resources, the gas produced from the RNG facility is considered carbon neutral. When RNG is used to meet customers' energy needs, measurable GHG reductions may be quantified. Additionally, in certain circumstances depending on the the RNG feedstock, the methane emissions that are captured may be quantified and expressed as measurable carbon offsets. These environmental benefits differentiate RNG from geologic natural gas. RNG and the associated environmental attributes will play an important role in achieving GHG emissions reductions.

RNG also offers a variety of economic benefits. Producing RNG has the potential to transform a costly waste burden into a local asset, reduce local budgets for waste management and fuel-purchasing, stimulate the evolution of local businesses, and create jobs up and down the supply chain. The food industry can benefit significantly from the local integration of RNG. Instead of paying for the unused food to be picked up and taken to a landfill, the food industry can instead divert their food waste to an RNG facility and avoid costly landfill tipping fees. The RNG production facility not only generates RNG, but also can provide nutrient rich biosolids that can be used as fertilizers and return nutrients to the soil for future use. This creates a more circular economy, where food is not wasted but, rather, beneficially used within the economy. RNG also provides a revenue stream for farmers, as manure can be acquired and used as a feedstock for RNG production. When RNG facilities are used at farms, they serve as a manure management system. The manure serves as a feedstock to create useable RNG from the otherwise waste methane, and the post-digestion process yields a usable effluent that can be used as fertilizer. Additionally, local jobs can be created during the construction and operation of RNG facilities. Temporary jobs are created during construction, with estimates of approximately 50 positions needed during project design and construction. Permanent jobs are created to operate and maintain the facility long-term. These jobs can include plant managers, technicians, biologists, and market analysts.

RNG is a developing resource for integration in the conventional natural gas system. States are at different stages in incorporating RNG into their statewide fuel resource mix. There is currently regulatory action, either voluntary or mandated, in 13 states across the country. The state of Georgia has strong RNG production potential. In fact, the American Biogas Council ranks Georgia as 4th out of 50 states for RNG production potential utilizing anaerobic digestion. Currently, AGL offers two transportation Tariff rates, TS-1 and TS-2, which allow third- parties to interconnect and utilize the gas network to transport locally sourced RNG. To date, AGL has three customers participating under the Tariff and have received many interconnection inquiries.

RNG projects provide tremendous opportunity to reduce GHG emissions. AGL recognizes the importance of providing customers clean, safe, reliable, and affordable energy. As AGL seeks to advance decarbonization opportunities for customers, renewable gas will play a key role. AGL is well positioned to draw on its initial learnings from interconnecting projects under the TS-1 and TS-2 tariffs and build on those learnings to make investments in renewable gas project opportunities to provide benefits to customers, communities, and the environment.

CHAPTER 9. CONCLUSION & ACTION PLAN

The 2022 i-CDP reflects the Company's plan to continue to deliver safe, reliable, affordable and clean energy to customers through ongoing and proposed pipeline safety, reliability and growth programs, continued implementation of industry best practices, increased focus on environmental initiatives, and sustained, proactive steps in response to continually changing circumstances, governmental regulations and market conditions. In addition to the items specifically contained in the conclusion of Chapter 1, pending Commission approval where necessary, the Company plans to take the following actions:

- Plan and manage the Capacity Supply Plan process to continue to maintain an appropriate array of interstate pipeline and out-of-state storage services to meet customers' needs;
- Build, operate, and maintain the necessary natural gas delivery infrastructure to ensure adequate reliability and serve the needs of customers in Georgia;
- Ensure full compliance with state and federal minimum standards to deliver gas safely to customers in the communities AGL serves;
- As appropriate, implement industry best practices that exceed the government-mandated minimum requirements;
- Design and implement programs to retain and grow the natural gas customer base that put downward pressure on rates for customers on the system and improve economic development and the economy for all Georgians; and
- Pursue opportunities to reduce emissions and increase supplies of renewable natural gas.

ATTACHMENT A. SRR TARIFF SHEET

Atlanta Gas Light **TERMS OF SERVICE**

All Rate Schedules
Original Sheet No. 25.1
Effective: January 1, 2022

25. System Reinforcement Rider (SRR)

25.1 Applicability

The SRR charge will apply to all Rate Schedules of the Company that contain a separate charge based on Dedicated Design Day Capacity.

25.2 Purpose

The purpose of this Rider is for the Company to recover certain cost associated with system reinforcement and pressure improvement projects approved by the Commission to be included within the SRR.

25.3 Billing Rate

A rate of $3.00 per Dt of DDDC per year shall be assessed based upon the terms of this Rider.

ATTACHMENT B. PROJECTED DESIGN DAY LOAD REQUIREMENT

PUBLIC DISCLOSURE

REDACTED

ATTACHMENT C. ARRAY OF INTERSTATE ASSETS

PUBLIC DISCLOSURE

REDACTED

ATTACHMENT D. RANGE OF REQUIREMENTS

PUBLIC DISCLOSURE

REDACTED

ATTACHMENT E. RNG STUDY

Renewable Natural Gas Opportunities

Atlanta Gas Light Company ("AGL") retained Concentric Energy Advisors to provide an overview of Renewable Natural Gas ("RNG"), describe potential roles of a natural gas utility in developing RNG opportunities, and to examine how investment in RNG by a natural gas utility may create increased customer value.

1. Overview of Renewable Natural Gas

The American Gas Association ("AGA") defines RNG as "any pipeline compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle CO_2 emissions than geological natural gas."[16]

For RNG to be suitable for introduction into the natural gas pipeline network, the initial raw biogas must be adequately processed to meet gas quality and end-use application standards. At a high level, this typically involves concentrating the methane content and removing any undesired constituents.

Treatment includes removing moisture, carbon dioxide, trace-level contaminates, and reducing the nitrogen and oxygen content. RNG injected into a natural gas pipeline commonly has a methane content of between 96 and 98 percent.

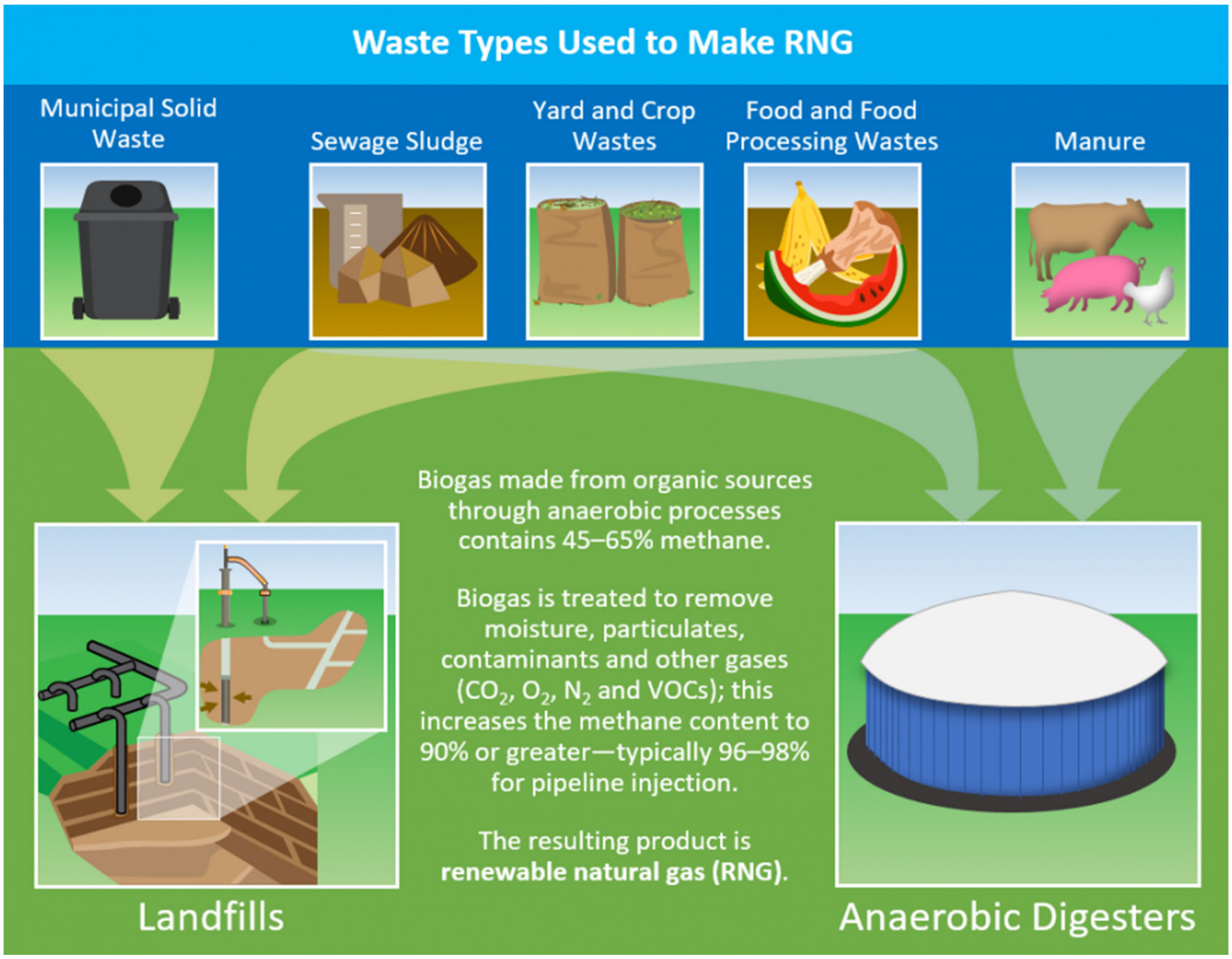
While RNG is fundamentally interchangeable with conventional natural gas, different RNG feedstocks pose different challenges for RNG quality and composition. For example, raw (unprocessed) biogas from a landfill facility is different than biogas from a dairy digester. Biogas constituents vary by feedstock and conversion technology, and testing requirements need to be aligned to optimize results and processing requirements.

RNG can be safely used in any end-use application that is typically fueled by natural gas, including: heating, cooling, water heating, cooking, industrial applications, transportation fuel, and electricity generation. The primary source of RNG is from capturing emissions from existing waste

[16] https://www.aga.org/natural-gas/renewable/

streams. In recent years, RNG has become increasingly available with approximately 50 trillion Btu per year of RNG injected into natural gas transportation and distribution systems from landfills, dairy digesters, and water resource recovery facilities ("WRRFs").[17]

The following illustration shows the types of feedstock used to create RNG:[18]



[17] Mintz, M. and P. Voss. Database of Renewable Natural Gas (RNG) Projects, 2020 Update, Argonne National Laboratory, October 2020, https://www.anl.gov/es/reference/renewable-natural-gas-database.

[18] https://www.epa.gov/lmop/renewable-natural-gas

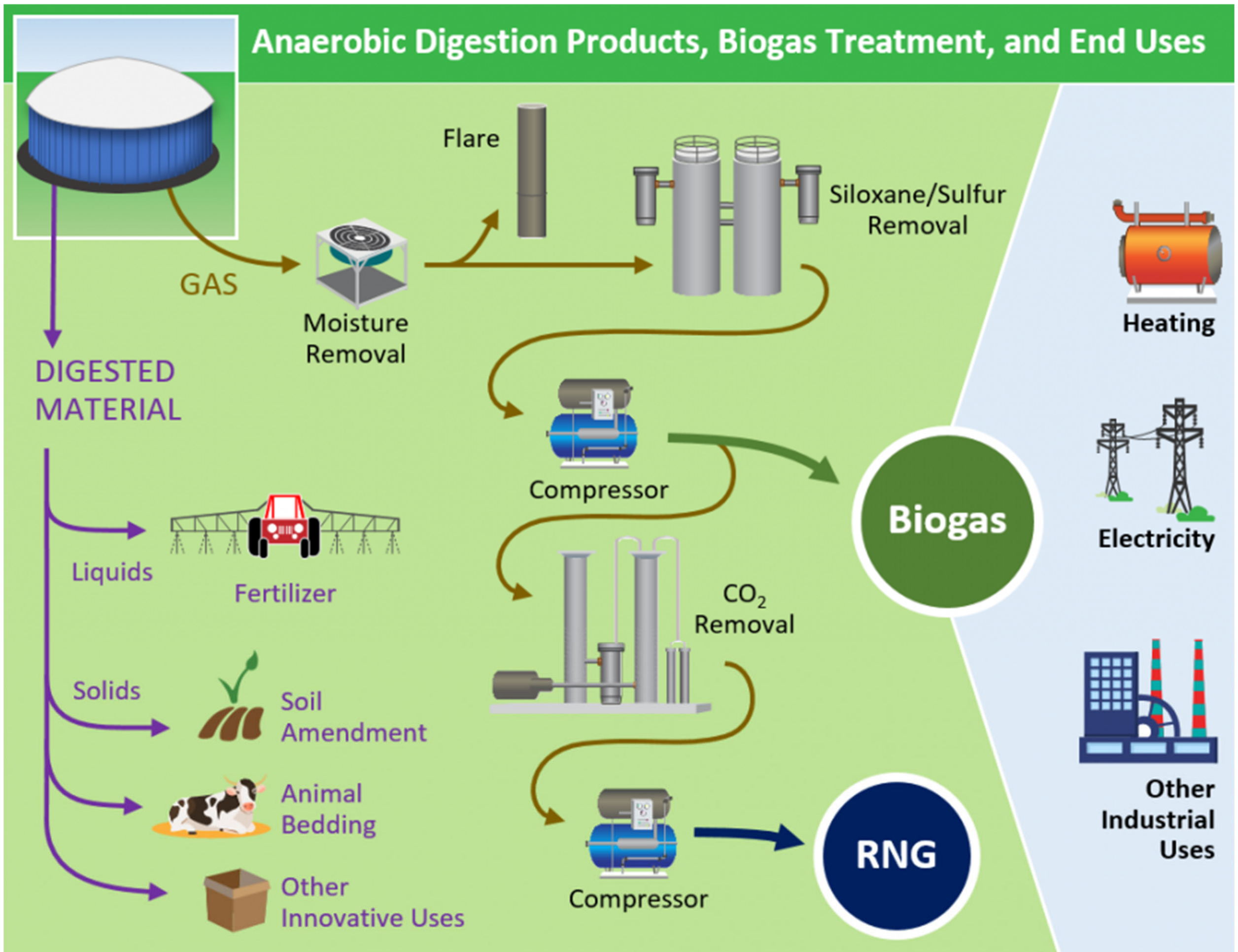
The table[19] below provides a more comprehensive list of RNG feedstock types:

Feedstock for RNG		Description
Anaerobic Digestion	Landfill gas (LFG)	A mix of gases, including methane (40–60%), produced by the anaerobic digestion of organic waste in landfills
	Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses
	Water Resource Recovery Facilities (WRRF)	In processing wastewater, a sludge is produced, which serves as the feedstock for RNG; wastewater consists of waste liquids and solids from residential, commercial and industrial water use
	Food waste	Commercial food waste, including from food processors, grocery stores, cafeterias, and restaurants, as well as residential food waste, typically collected as part of waste diversion programs
Thermal Gasification	Agricultural residue	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested including unusable portion of crop, stalks, stems, leaves, branches, and seed pods
	Forestry and forest product residue	Biomass generated from logging, forest and fire management activities, and milling, including logging residues, forest thinnings, mill residues, and materials from public forestlands (with the exception of specially designated forests such as roadless areas, national parks, and wilderness areas)
	Energy crops	Includes perennial grasses, trees, and annual crops that can be grown to supply large volumes of uniform and consistent feedstocks for energy production
	Municipal solid waste (MSW)	Refers to the non-biogenic portion of waste that would be landfilled after diverting other waste products (e.g., food waste or other organics), including construction and demolition debris and plastics

RNG is produced over a series of steps: collection of a feedstock; delivery of the feedstock to a processing facility to produce biogas; biogas conditioning to achieve pipeline quality natural gas; and compression, odorization, and injection into a natural gas transportation and distribution system.

[19] *See*, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, An American Gas Foundation Study Prepared by ICF, Page 7, https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

The process for landfill gas and for anaerobic digestion are illustrated below[20]:



The diagram above demonstrates the difference uses of “Anaerobic Digestion Products” and helps distinguish the difference between Biogas and RNG. It is helpful to view these products as steps in refinement – base level products such as the liquids and solids, require little refinement, requiring only basic moisture and particulate removal. Biogas requires additional moisture and contaminant removal to become pipeline quality – a substantial refinement process that requires the use of technologies such as solvent scrubbing and/or membrane screening. Uses of Biogas are typically lower Btu content applications such as industrial boilers. The highest level of

[20] https://www.epa.gov/lmop/renewable-natural-gas

refinement, or advance treatment, is necessary to attain pipeline quality RNG. This advanced refinement includes removal of CO_2, O_2, N_2, VOCs and siloxanes.[21]

2. The Current Market for RNG

The current market for RNG is in two sectors: Transportation and Non-Transportation.

A. The Transportation Market Sector

Most RNG is currently consumed as a motor vehicle fuel in the transportation sector because of incentives. More specifically, RNG is eligible to generate valuable incentives from the federal Renewable Fuel Standard (RFS) program administered by the US Environmental Protection Agency (US EPA). Additionally, RNG used in California or Oregon as a vehicle fuel can also generate incremental value through California's Low Carbon Fuel Standard (LCFS) program or Oregon's Clean Fuels Program (CFP). For RNG suppliers, these state programs are attractive because the credits generated in either program are in addition to the federal RFS incentives. Because of these incentives, RNG has made substantive contributions to California's LCFS program. By the end of 2020, RNG was supplying about 90% of all natural gas consumed as transportation fuel in California.[22]

Renewable Identification Numbers ("RINs") are credits that are used for compliance in the RFS program. RINs are the currency of the RFS program and they are generated by renewable fuel producers or importers based on production, import or sale of renewable fuels. RINs are an environmental commodity and the quantity of RIN's generated depends on the feedstock that was used to produce the fuel. California's LCFS program operates on a simple system of deficits and credits. Credits are generated by lower carbon fuels like RNG, and the number of credits depend on the carbon intensity or greenhouse gas ("GHG") footprint of the low carbon fuel.[23]

B. The Non-Transportation Market Segment

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[21] "An Overview of Renewable Natural Gas from Biogas", EPA 456-R-20-001 dated July 2020, Page 20.

[22] http://biomassmagazine.com/articles/17518/rng-helps-reach-carbon-negative-milestone-in-california

[23] https://www.epa.gov/renewable-fuel-standard-program/renewable-identification-numbers-rins-under-renewable-fuel-standard

The GHG reductions and the valuable environmental attributes associated with RNG, provide market opportunities for RNG. RNG has the potential to significantly reduce GHG emissions and form part of a cost-effective deep decarbonization strategy. The mix of regulatory and voluntary decarbonization commitments by corporations, gas utilities, and other key actors have helped to create a demand for RNG in non-transportation markets over the last several years.

Using RNG for residential, commercial, and industrial natural gas customers provides two critical advantages relative to other measures: 1) it utilizes existing natural gas transmission and distribution infrastructure, which is highly reliable and efficient, and 2) it allows for the use of the same consumer equipment as conventional gas (e.g., furnaces, stoves), avoiding expensive retrofits and upgrades required for fuel-switching.

While there is clearly a near-term focus on reaping the benefits of credits generated in the LCFS program and RINs in the RFS program, the long-term potential for increased utilization of RNG outside the transportation sector is larger and potentially more robust.

3. Benefits of RNG

The following materials from the U.S. EPA's website[24] summarize the benefits of RNG. According to the EPA, RNG has the following benefits:

- **Fuel diversity benefits:** RNG can be used as a baseload fuel source with high availability rates, and depending on the RNG location and interconnect, can provide delivery system operational benefits.
- **Economic benefits:** The development of RNG projects can benefit the local economy through temporary and permanent employment, ad valorem taxes, and help with local waste management.
- **Greenhouse gas emission reductions and local air quality benefits:** RNG is comprised primarily of methane and its emissions profile compares favorably to fossil natural gas and petroleum fuels. RNG projects capture and recover methane produced at a landfill or anaerobic digestion facility, which is otherwise released into the atmosphere.

4. Barriers to RNG Development and Adoption

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[24] https://www.epa.gov/lmop/renewable-natural-gas

RNG project development faces two main types of barriers: economic and technical.[25] Technical barriers, although formidable, may be overcome through technology advancements (e.g., advancements in particle removal, gas separation, etc.) and advancements in processes (e.g., feedstocks, aggregation of biogas at RNG processing plants, etc.). Economic barriers, however, are more difficult to overcome when comparing RNG to fossil-derived natural gas. The cost of feedstock acquisition, aggregation and processing, methane separation to achieve pipeline quality gas, and the construction of pipeline facilities to deliver pipeline quality RNG into interstate pipelines or local utility distribution systems is more expensive than modern fossil-based natural gas extraction and gathering. An EPA collaborative study published in 2016 determined a cost range of $7 per million Btu (very large-scale) to $25 per million Btu (small-scale) for projects upgrading biogas to RNG for pipeline injection.[26] More recent studies have indicated that the majority of the RNG produced in a high resource potential scenario will be available in the range of $7-$20/MMBtu.[27] As discussed below, utility investment in RNG may assist in bringing down these costs.

5. National Adoption of RNG

RNG is a developing resource for integration in the conventional natural gas system. States are at different stages in incorporating RNG into their statewide fuel resource mix. Below is an American Gas Association ("AGA") graphic, updated in January 2021, which depicts in green the 26 states identified by AGA as being currently engaged in activity that promotes RNG, either through legislative, regulatory, or utility-led action.

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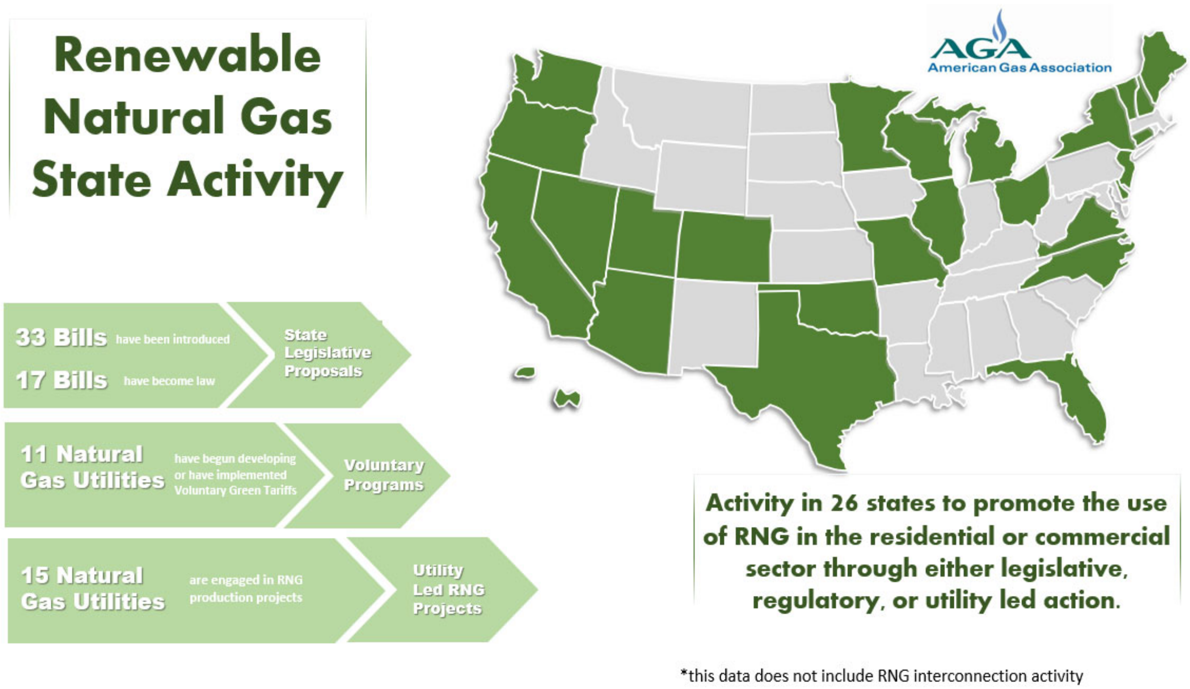
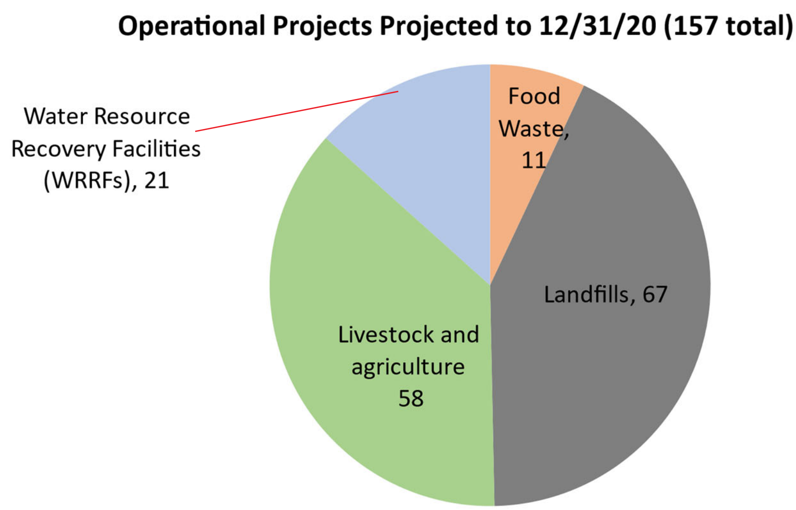
[25] EPA 456-R-20-001 Page 27.

[26] Ibid, page 28.

[27] *See*, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, An American Gas Foundation Study Prepared by ICF, Page 64, https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.


Renewable Natural Gas State Activity
33 Bills have been introduced
17 Bills have become law
State Legislative Proposals
11 Natural Gas Utilities have begun developing or have implemented Voluntary Green Tariffs
Voluntary Programs
15 Natural Gas Utilities are engaged in RNG production projects
Utility Led RNG Projects
AGA American Gas Association
Activity in 26 states to promote the use of RNG in the residential or commercial sector through either legislative, regulatory, or utility led action.
*this data does not include RNG interconnection activity

There are a growing number of operational or planned to be operational RNG projects as of 2020. The data below shows the 157 actual/planned operational projects identified by the Argonne National Laboratory ("ANL")[28] by feed stock type:

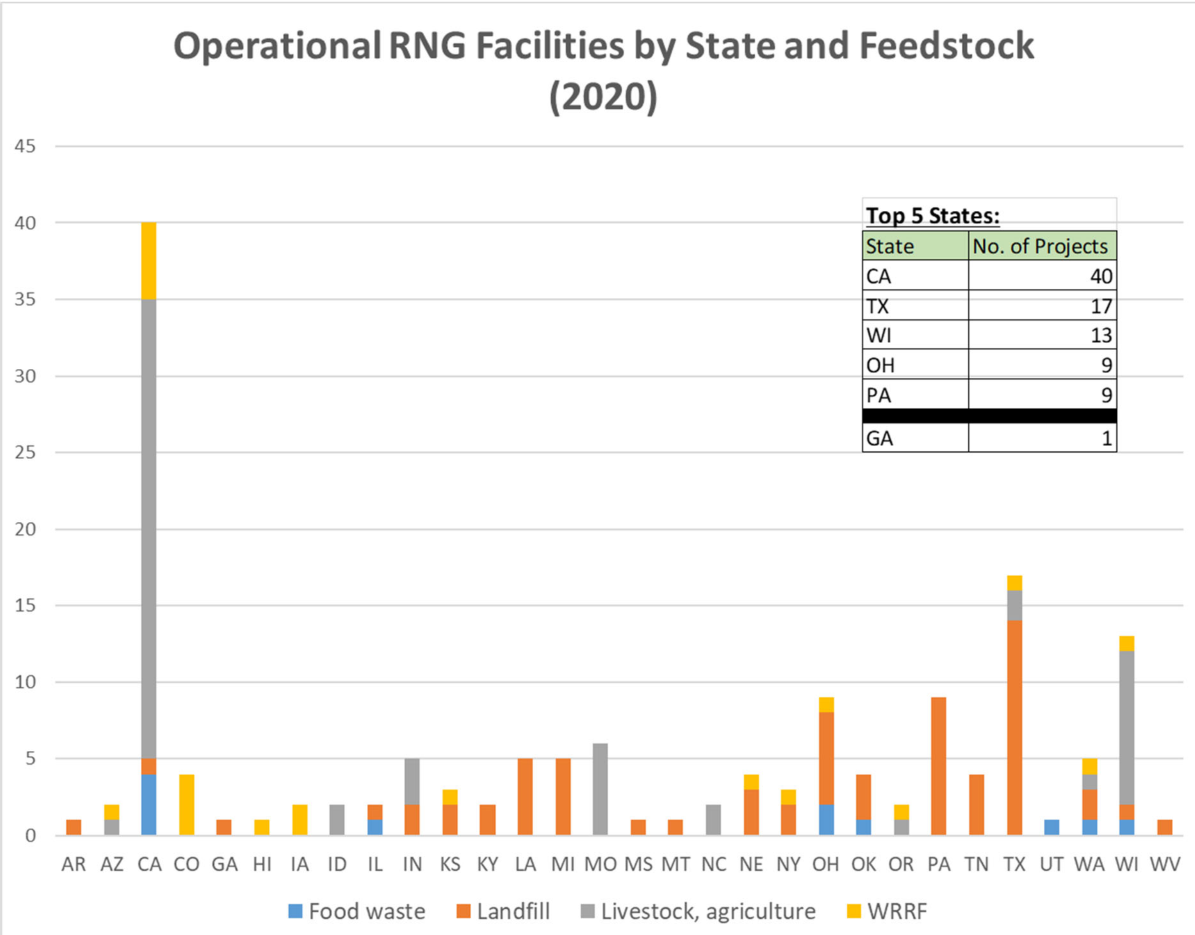


There are also 155 additional projects identified by ANL that are either under construction or planned to be constructed by the end of 2020, bringing the total number of projects to 312:

PROJECTS BY TYPE & STATUS, PROJECTED TO 12/31/2020	Operational (projected to 12/31/2020)	Under Construction (projected to 12/31/2020)	Planned (projected to 12/31/2020)	Total Projects by Feedstock (projected to 12/31/2020)
Food Waste	11	2	7	20
Landfills	67	5	21	**93**
Livestock, agriculture	58	62	50	**170**
Water Resource Recovery Facilities (WRRFs)	21	7	1	**29**
Projected 12/31/2020 Totals by Project Status	157	76	79	**312**

[28] Mintz, M. and P. Voss. Database of Renewable Natural Gas (RNG) Projects, 2020 Update, Argonne National Laboratory, October 2020, https://www.anl.gov/es/reference/renewable-natural-gas-database.

The 157 operational facilities identified by ANL are located throughout the U.S. – currently in 30 different states, including Georgia:



The detailed list of the 157 operational facilities is shown in Appendix B.

6. A Natural Gas Utility's Role in RNG

Utilities are pursuing regulatory initiatives that support the development of RNG, including voluntary tariffs and procurement programs, RNG conditioning and interconnection tariffs, and utility ownership structures. Those potential pathways are summarized below.

A. Utility Interconnect. As an *interconnection provider*, a utility would construct, install and maintain a pipeline and the associated facilities to connect the RNG facility into the utility's existing pipelines.

B. Utility Offtake. Through an *offtake arrangement*, a utility would purchase RNG from an RNG production facility or facilities, adding it to the utility's supply portfolio and potentially displacing fossil-based natural gas supply.

C. Utility Ownership. By a *utility investing* in an RNG production facility, a utility would own or have an interest in the ownership and operation of the RNG production facility.

A. Utility Interconnection and Gas Quality

Interconnection serves a vital role in an RNG project—it is the point at which gas quality is monitored, non-compliant gas is prevented from entering the system, and injection pressure is achieved, odorization is added (if required), and injected RNG is metered. Generally, some additional infrastructure must be installed to receive RNG into existing natural gas systems and these may represent a substantial portion of the project costs.

B. Utility as an Off-taker

In this example, a utility would execute an offtake agreement to purchase RNG from a third-party production facility or facilities. The utility or gas marketer may then make RNG available to customers through a voluntary opt-in program or through one or more purchased gas programs.

The role of a utility is straightforward in this pathway: The gas utility would execute agreements with owners of RNG production facilities. For the natural gas market, the role of the regulated utility and the role of a marketer are similar – that is to purchase RNG from a third-party on behalf of customers. Current market conditions, including the fundamentals of RNG supply and demand, and potential limitations on terms of delivery (e.g., length of contract and associated volumes), would affect the purchase agreement.

RNG developers would likely maintain pricing power in this scenario, especially in the context of increasing pressures on RNG demand. RNG developers would be responsible for delivering the agreed-to volumes and ensuring stability of supply, as required by the purchase agreement.

However, utilities as an off-taker have several options to reduce the price of RNG, including:

- Leveraging a competitive request for proposal process;

- Accommodating long-term (e.g., 10+ year) agreements, which have the potential to stabilize financing and expected returns and providing clear incentives to reduce costs;
- Developing local partnerships, which may provide a more attractive end use or offtake for the RNG than an external party;
- Using Environmental Attributes creatively, where a utility could use RINs from the federal RFS as a means to reduce RNG procurement costs; and
- Providing the RNG developers certain contract flexibility that may not be available from potential non-utility purchasers.

The RFS and LCFS regulatory programs that currently incentivize RNG favor its use in the transportation sector. The high value of the incentives in these regulatory programs has the potential to inflate RNG prices in voluntary markets.

C. Utility as an Owner

In this scenario, a utility would acquire an ownership interest in an RNG production facility, deliver that RNG into its system, and recover the revenue requirements through rates. Utility investment in RNG production facilities will impact RNG production costs, as discussed below. Furthermore, utility investment may provide local benefits such as economic and system benefits (e.g., local temporary and/or permanent employment, locational system pressure / supply enhancement). Utility ownership can reduce overall RNG costs through the following:

1. **Lower cost of capital**. A developer's cost of capital will likely be in excess of a utility's costs of capital because developers require a higher return on equity than utilities to compensate for development risk, while a utility's cost of equity and debt financing is regulated. A natural gas utility's lower cost of equity and longer debt term provide a clear customer benefit for utilities to invest in RNG production facilities.
2. **Lower RNG production costs**. RNG developers commonly utilize the highly lucrative transportation market as an offtake to the RNG and environmental commodities. Alternatively, some RNG developers seek an off-taker agreement (gas purchase agreement) to supply RNG at a specified price for a specified term. Any gas purchase agreement would likely include significant risk premium in the RNG commodity price, and may contain contractual terms and conditions that the utility would not be subjected to if the utility owned the facility (e.g., minimum annual volumes, etc.). If the regulated utility is the owner, then the project will be placed into its rate base and will be depreciated over (presumably) a longer period-of-time (e.g., 25+ years) and will only recover the actual cost of service at the utility's weighted average cost of capital.
3. **Quality Assurance.** Utility ownership should also have a positive impact on the process of accepting RNG into its distribution system. As noted, earlier RNG must be processed to meet system quality standards and be acceptable as a fuel source. Generally, utilities

would have to build and operate the interconnection and testing facilities that would be redundant to the facilities installed by the project developer. Having the utility as the producer will eliminate the need for duplicative measuring and processing equipment and expense.

4. **Supply Diversity.** A utility that owns the RNG facility will be able to deal with variations in RNG production and utilize the RNG asset as a controllable, on-system supply resource.

5. **Locational Advantages.** A further advantage of utility ownership is that the facilities will be located in a utility's service area and be available to deal with and take advantage of local RNG sources rather than incurring transportation costs to move the gas from the source of production to the utility's system. Utilities are long-standing members of the communities they serve, and a utility's investment in an RNG project provides operational and financial stability. Locating RNG facilities in a utility's service area will also provide economic benefits to the local and state economy. In addition to the temporary jobs created during the construction period there will be permanent jobs created from the ongoing plant operations. This will extend not only to plant employees but to supplier companies, the feedstock suppliers and other residual product companies. Locally placed facilities will also help to address local waste management issues. Utility ownership will also in increased tax collections to the state in the form of Ad valorem (property) taxes, both business and personal income taxes, and sales taxes.

6. **Environmental Attributes.** Utility ownership of the RNG facilities will enable the utility to capture any environmental attributes (without a premium markup from a 3rd party) that can inure to the benefit of the utility and the utility's customers in the form of reduced energy prices.

In sum, providing the utility with an opportunity to develop and own RNG facilities will provide benefits to customers and the region as a whole through:

- Lower cost of capital;
- Increased operation efficiencies and reduce costs;
- Temporary jobs during construction;
- Permanent jobs during operation for plant employees, supplier company employees, and residual product company employees;
- Development of a local cycle of economic opportunities for those who provide the feedstock (local farmers, food processors, landfill operators, water treatment operators, etc.) and for those who market the residual by products;
- Ensures that local waste challenges are addressed locally;
    - Increases local and state tax base from Ad valorem taxes, Business and Personal income taxes, and Sales taxes;

- Utility can effectively compete for economic development candidates that have clean energy options as a threshold site selection criterion;
- Utility can better accommodate the occasional downtime in RNG production because of the broad array of diverse supply options within a utility's supply asset portfolio;
- Utility can empower smaller customers who want to contribute to emission solutions, providing opportunities that typically have been available only to large end-use customers, and
- Utility can better accommodate the ramp up of customer demand as residential and small business customers are afforded the option of RNG as an environmentally superior energy choice.

7. Conclusion

RNG is small part of the current natural gas supply portfolio but it is seeing growing importance as a renewable energy option and as a GHG strategy. While RNG currently is being primarily used in the transportation market there are over 150 current and proposed projects to expand its use in both the transportation and non-transportation markets.

Utilities are pursuing regulatory initiatives that support the development of RNG, including voluntary tariffs and procurement programs, RNG conditioning and interconnection tariffs, and utility ownership structures. Each of these initiatives will provide different benefits to the customers. While AGL has some experience in providing interconnections it should be encouraged to explore other pathways to determine how to provide the maximum benefit of RNG to its customers and the State as a whole.

Appendix A: Sample RNG Project

Boyd County Sanitary (formerly Big Run) Landfill

Municipal Solid Waste to Pipeline-Injected RNG for Directed Biogas

1. Location: Ashland, Kentucky (Boyd County)
2. RNG Start Date: September 2020[29]
3. Project Developer: Big Run Power Producers
4. Landfill Owner: Rumpke Waste & Recycling, which acquired the landfill in 2019 and changed its name from Big Run to Boyd County Sanitary Landfill
5. The onsite gas upgrading and conditioning facility takes raw landfill gas ("LFG"), cleans it using membrane and PSA technologies, and injects the resulting RNG into the Columbia Gulf Transmission system at a point about two miles away from the landfill.
6. Argonne National Laboratory estimates that the facility upgrades about 3.17 million cubic feet of gas/day, approximately 55% of the 5.76 million cubic feet/day of total raw landfill gas collected.
    a. Annually, ANL estimates that this equates to 1.04 million MMBtu of upgraded gas produced by the facility and an estimated 400,000 metric tons of CO2 equivalent emissions avoided.[30]
    b. The plant's 2-mile interconnection pipeline to the Columbia Gulf Transmission system has an operationally available capacity of 6.6 million cubic feet/day and had a total capital investment of roughly $40 million.[31 32]
7. The primary end user of the RNG produced by the Boyd County Sanitary plant is L'Oreal, a global cosmetic and manufacturing leader, which signed a 15-year agreement to purchase approximately 40 percent of the RNG produced from Big Run. The facility is located 135 miles away from L'Oréal's largest manufacturing plant in Florence, KY.[33]
    a. The venture is designed to help further the company's internal carbon emissions reduction goal, as well as to help fuel producers comply with the EPA's Renewable Fuel Standard.
    b. For the first five years after the start of operation, RNG buyer L'Oréal USA will sell RINs in the vehicle fuel marketplace to recoup their investment. To avoid double counting of the environmental attributes, L'Oréal will also buy carbon offsets for their facilities from a different RNG project. Starting in the sixth year, L'Oréal will stop selling RINs and instead will use 40 percent of the RNG from the Boyd County Sanitary Landfill to supply the company's U.S. facilities with 280,000 MMBtu per year for thermal energy use, mainly for heating buildings and process water.

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[29] EPA Landfill Gas Energy Project, data published March 2021, https://www.epa.gov/lmop/landfill-gas-energy-project-data

[30] Mintz, M., P. Voss, M. Tomich, and A. Blumenthal. Database of Renewable Natural Gas (RNG) Projects, Argonne National Laboratory, October 2018, https://www.anl.gov/es/reference/renewable-natural-gas-database

[31] Kentucky Power Company, KPSC Case Nol. 2018-00378, Exhibit 2, p. 2 of 3

[32] Columbia Gulf Transmission Info Post, Daily Operational Information retrieved April 8, 2021

[33] Portsmouth Daily Times, https://www.portsmouth-dailytimes.com/news/25187/landfill-eyed-as-source-for-renewable-natural-gas

c. L'Oréal estimates that its venture is expected to eliminate the equivalent of 1.8 million gallons of gasoline consumed per year.

8. Rumpke Waste & Recycling acquired the landfill in late 2018 after its previous owner divested itself of several landfills on the East Coast. The landfill's name was subsequently changed from Big Run to Boyd County Sanitary Landfill.[34]

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[34] The Daily Independent, https://www.dailyindependent.com/news/rumpke-to-own-big-run-landfill/article_a7c7700c-e788-11e8-bc0c-67f44431a719.html

Appendix B: 2021 Operational RNG Projects List			
The projects listed below are expected to be Operational by 12/31/2020.			
PROJECT TYPE	**NAME**	**STATE**	**OPERATIONAL CALENDAR 2020**
Food waste	Blue Line Biogenic CNG Facility	CA	Yes
Food waste	CR&R Perris Transfer Station and MRF	CA	Yes
Food waste	Northstate Rendering Anaerobic Digester (Biogas Energy)	CA	Yes
Food waste	Rialto Bioenergy Facility	CA	Yes
Food waste	Archer Daniels Midland corn processing facility	IL	Yes
Food waste	Central Ohio BioEnergy (Equilibrium Capital)	OH	Yes
Food waste	Zanesville Energy (Quasar)	OH	Yes
Food waste	Seaboard Foods/High Plains Bioenergy	OK	Yes
Food waste	Wasatch Resource Recovery	UT	Yes
Food waste	Impact Bioenergy Vashon Island	WA	Yes
Food waste	New Organic Digestion, Denmark (Big Ox)	WI	Yes
Landfill	City of Fort Smith Landfill (Morrow Renewables)	AR	Yes
Landfill	Altamont Landfill (Waste Management)	CA	Yes
Landfill	Live Oak Landfill	GA	Yes
Landfill	Milam Recycling and Disposal Facility (Waste Management)	IL	Yes
Landfill	Randolph Farms Landfill	IN	Yes
Landfill	Indy High BTU/Southside	IN	Yes
Landfill	Hamm Sanitary Landfill/Renewable Power Producers	KS	Yes
Landfill	Johnson County Landfill (formerly Deffenbaugh) (WM, Aria)	KS	Yes
Landfill	Big Run	KY	Yes
Landfill	Outer Loop	KY	Yes
Landfill	Jefferson Davis Parish Landfill	LA	Yes
Landfill	Keithville (Republic, Element Markets)	LA	Yes
Landfill	River Birch Landfill	LA	Yes
Landfill	St. Landry Parish Landfill	LA	Yes
Landfill	Waste Connections Timberlane	LA	Yes
Landfill	Richfield Landfill ("Blue Sky") (Blue Skies Energy)	MI	Yes
Landfill	Riverview Land Preserve	MI	Yes
Landfill	Sauk Trail Hills Landfill (Republic Services, Aria)	MI	Yes
Landfill	Waste Management Woodland Meadows (WM, Ameresco)	MI	Yes
Landfill	Westside Recycling and Disposal Facility (WM, DTE Biomass Energy)	MI	Yes
Landfill	North East Mississippi Regional Landfill (Air Liquide)	MS	Yes
Landfill	Billings Regional Landfill	MT	Yes
Landfill	Butler County (Waste Connections, Aria)	NE	Yes
Landfill	Douglas County Landfill-- State Street (BioResource Development)	NE	Yes
Landfill	Sarpy County Landfill, BioResource Development N1	NE	Yes
Landfill	Fresh Kills Landfill (Montauk)	NY	Yes

Landfill	Seneca Meadows SWMF (Progressive)	NY	Yes
Landfill	American (WM)	OH	Yes
Landfill	APEX Sanitary Landfill (Apex, Montauk)	OH	Yes
Landfill	Franklin County Sanitary Landfill (Aria)	OH	Yes
Landfill	Pinnacle Road Landfill (North Sanitary Landfill) (WM, DTE Biomass Energy)	OH	Yes
Landfill	Rumpke Sanitary Landfill	OH	Yes
Landfill	Stony Hollow Landfill (WM, DTE Biomass Energy)	OH	Yes
Landfill	Oklahoma City Landfill (Waste Connections, Aria)	OK	Yes
Landfill	Southeast Oklahoma City (Republic, Aria)	OK	Yes
Landfill	Southern Oklahoma Regional Disposal Landfill	OK	Yes
Landfill	Advanced Disposal Services Greentree Landfill, LLC (Advanced Disposal, EDF Renewables)	PA	Yes
Landfill	Imperial Sanitary Landfill (Republic, EDF Renewables)	PA	Yes
Landfill	Laurel Highlands Landfill (WM, Montauk Energy)	PA	Yes
Landfill	Monroeville Landfill (WM)	PA	Yes
Landfill	Seneca Landfill	PA	Yes
Landfill	Shade Landfill (WM, Montauk)	PA	Yes
Landfill	Southern Alleghenies Landfill (WM, Montauk)	PA	Yes
Landfill	Valley Landfill	PA	Yes
Landfill	Westmoreland County Sanitary Landfill	PA	Yes
Landfill	Carter Valley Landfill	TN	Yes
Landfill	Meadow Branch Landfill (Waste Connections)	TN	Yes
Landfill	North Shelby Landfill (Republic, Aria)	TN	Yes
Landfill	South Shelby (Republic, Aria)	TN	Yes
Landfill	Atascocita/Humble (WM, Montauk)	TX	Yes
Landfill	Edinburg Landfill (Morrow)	TX	Yes
Landfill	Fort Bend Regional Landfill (DTE Biomass Energy)	TX	Yes
Landfill	Galveston County Landfill	TX	Yes
Landfill	Greenwood Farms Landfill/Tyler (Morrow "East Texas")	TX	Yes
Landfill	McCarty Road Landfill (Republic, Montauk)	TX	Yes
Landfill	McCommas Bluff Landfill (Energy Power Partners)	TX	Yes
Landfill	North Texas Municipal Water District, Melissa ("NTMWD") (Morrow)	TX	Yes
Landfill	Pine Hill/Longview (Kilgore) (Morrow)	TX	Yes
Landfill	Renovar Arlington (Coalition database)	TX	Yes
Landfill	Republic Services Blue Ridge Landfill ("Houston") (Morrow)	TX	Yes
Landfill	Seabreeze Environmental Landfill (Seabreeze, DTE Biomass)	TX	Yes
Landfill	Skyline Landfill	TX	Yes
Landfill	Turkey Creek Landfill/Alvarado (Morrow)	TX	Yes
Landfill	Cedar Hills Regional Landfill	WA	Yes
Landfill	Roosevelt Regional Landfill (Republic)	WA	Yes
Landfill	Dane County Landfill #2 - Rodefeld (BioCNG)	WI	Yes

Landfill	City of Charleston Landfill (WM)	WV	Yes
Livestock, agriculture	Wastewater Opportunity Fund Southwest GGP LLC (Green Gas Partners Stanfield Project)	AZ	Yes
Livestock, agriculture	4K Dairy	CA	Yes
Livestock, agriculture	ABEC Lakeview Farms Dairy Digester	CA	Yes
Livestock, agriculture	Aukeman Dairy	CA	Yes
Livestock, agriculture	Belonave Dairy	CA	Yes
Livestock, agriculture	Bos Farms Dairy	CA	Yes
Livestock, agriculture	BV Dairy	CA	Yes
Livestock, agriculture	Circle A Dairy Digester Fuel Pipeline Project (Calgren)	CA	Yes
Livestock, agriculture	Cloverdale Dairy	CA	Yes
Livestock, agriculture	Cornerstone	CA	Yes
Livestock, agriculture	Dykstra	CA	Yes
Livestock, agriculture	El Monte	CA	Yes
Livestock, agriculture	Hamstra Dairy	CA	Yes
Livestock, agriculture	Hilarides Dairy	CA	Yes
Livestock, agriculture	K&M Visser Dairy Digester Fuel Pipeline Project (Calgren)	CA	Yes
Livestock, agriculture	Legacy Dairy Digester Fuel Pipeline project (Calgren)	CA	Yes
Livestock, agriculture	Little Rock	CA	Yes
Livestock, agriculture	Moonlight Dairy	CA	Yes
Livestock, agriculture	Pixley Dairy Digester Fuel Pipeline Project (Calgren)	CA	Yes
Livestock, agriculture	R Vander Eyk Dairy Digester Fuel Pipeline Project (Calgren)	CA	Yes
Livestock, agriculture	Rancho Teresita Dairy Biogas	CA	Yes
Livestock, agriculture	Riverbend	CA	Yes

Livestock, agriculture	Riverview Diary	CA	Yes
Livestock, agriculture	S&S Dairy	CA	Yes
Livestock, agriculture	Scheenstra Dairy Biogas	CA	Yes
Livestock, agriculture	Sousa and Sousa	CA	Yes
Livestock, agriculture	T&W Dairy	CA	Yes
Livestock, agriculture	Trilogy Dairy	CA	Yes
Livestock, agriculture	Udder Dairy	CA	Yes
Livestock, agriculture	Valadao	CA	Yes
Livestock, agriculture	Vander Poel	CA	Yes
Livestock, agriculture	AG Power DCD, unnamed farm	ID	Yes
Livestock, agriculture	AG Power Jerome LLC	ID	Yes
Livestock, agriculture	RDF Jasper (Bos, Herrema and Windy Ridge Farms)	IN	Yes
Livestock, agriculture	RDF Prairie's Edge Dairy 1 (formerly Fair Oaks 1)	IN	Yes
Livestock, agriculture	RDF Prairie's Edge Dairy 2 (formerly Fair Oaks 2)	IN	Yes
Livestock, agriculture	Roeselin South Meadows Farms	MO	Yes
Livestock, agriculture	Roeslein Alternative Energy - Homan	MO	Yes
Livestock, agriculture	Roeslein Alternative Energy - Somerset	MO	Yes
Livestock, agriculture	Roeslein Locust Ridge	MO	Yes
Livestock, agriculture	Roeslein Ruckman	MO	Yes
Livestock, agriculture	Roeslein Valley View	MO	Yes
Livestock, agriculture	Optima KV	NC	Yes
Livestock, agriculture	Optima Tar Heel	NC	Yes
Livestock, agriculture	Three Mile Canyon Farms	OR	Yes

Livestock, agriculture	Cactus Digester Gas Utilization Plant (Coalition database)	TX	Yes
Livestock, agriculture	JBS USA Dalhart	TX	Yes
Livestock, agriculture	George DeRuyter & Sons Dairy Digester (Brightmark Augean RNG Project)	WA	Yes
Livestock, agriculture	Brightmark Energy Demeter Project	WI	Yes
Livestock, agriculture	Calumet Renewable Energy (Dairy Dreams, Pagels Ponderosa, Maple Leaf and Grotegut Dairies)	WI	Yes
Livestock, agriculture	Dane Renewable Energy (Statz Bros Dairy)	WI	Yes
Livestock, agriculture	Holsum Dairies	WI	Yes
Livestock, agriculture	Kewaunee Renewable Energy (Kinnard Dairy)	WI	Yes
Livestock, agriculture	New Chester Renewable Energy (New Chester Dairy)	WI	Yes
Livestock, agriculture	Rosendale Renewable Energy (Rosendale Dairy)	WI	Yes
Livestock, agriculture	US Gain S&S Jerseyland Dairy	WI	Yes
Livestock, agriculture	US Gain Cloverhill Dairy	WI	Yes
Livestock, agriculture	US Gain Dallmann East River Dairy	WI	Yes
WRRF	91st Avenue, Phoenix	AZ	Yes
WRRF	City of San Mateo Wastewater Treatment Plant	CA	Yes
WRRF	Ellis Creek Water Recycling Facility	CA	Yes
WRRF	Las Gallinas Valley Sanitary District	CA	Yes
WRRF	Los Angeles County Sanitation Districts Joint Water Pollution Control Plant	CA	Yes
WRRF	Point Loma Wastewater Treatment Plant	CA	Yes
WRRF	Longmont Wastewater Treatment Plant	CO	Yes
WRRF	Persigo Wastewater Treatment Plant	CO	Yes
WRRF	City of Boulder WRRF	CO	Yes
WRRF	South Platte Water Renewal Partners	CO	Yes
WRRF	Honouliuli Wastewater Treatment Plant	HI	Yes
WRRF	Dubuque Water and Resource Recovery Center	IA	Yes
WRRF	Sioux City WWTP	IA	Yes
WRRF	Warrior Biogas Reuse Project	KS	Yes
WRRF	Lincoln, Nebraska Theresa Street WWTP	NE	Yes
WRRF	Newtown Creek Wastewater Treatment Plant	NY	Yes
WRRF	Newark Wastewater Treatment Plant	OH	Yes

WRRF	Columbia Boulevard Wastewater Treatment Plant	OR	Yes
WRRF	Dos Rios Water Recycling Center	TX	Yes
WRRF	South Wastewater Treatment Plant (King County)	WA	Yes
WRRF	Janesville Wastewater Treatment Plant	WI	Yes

MEMORANDUM

TO: All Georgia Natural Gas Operators

FROM: Michelle Thebert, Director Facilities Protection Unit

RE: Review of Over-Pressure Protection Devices and Procedures—Best Practices

DATE: October 15, 2018

Following the recent events on a distribution system in Massachusetts, I am asking that all Georgia natural gas pipeline operators immediately review current procedures relating to pressure regulation, over-pressure protection, and energizing new and replacement pipelines. While all the details and events that led to the Massachusetts incident are not currently known, there are several steps that Georgia pipeline operators can take to verify that Georgia's gas transmission and distribution systems continue to operate safely.

The following Best Practices should be reviewed by each operator and discussed throughout the operator's construction and engineering departments:

1. If applicable, all tie-in work and abandonments on high pressure to low pressure pipeline systems should cease until the operator reviews and analyzes its procedures relating to these activities. An engineering review of each new and ongoing project should occur and a job specific procedure should be developed for every main-to-main tap, tie-in, retirement and pressure upgrade. This review should include all piping, pressure regulation and relief devices, and sensing line locations. Once this review is completed, documented, and job specific procedures developed, training of all operator and contractor personnel that will participate in the high/low pressure tie-in, abandonment, and/or regulator station operations must be verified prior to commencement of activities. This training should include job specific abnormal operating conditions (AOCs) and actions to be taken if/when AOCs are recognized.

2. For all work within, or in close proximity, to a regulator station, a pre-job briefing shall occur for all involved personnel to ensure that employees are knowledgeable regarding the planned work, covered tasks involved, and potential abnormal operating conditions that may occur – and actions to take if they do occur.

3. All work within, or in close proximity to, a regulator station must be performed under the direction of employees who are knowledgeable in the design, construction, operation, and maintenance of regulator stations. These employees should be company employees or be very familiar with company policies and procedures.

4. The qualifications to perform any covered task shall be verified prior to commencement of activities. This must include verification of the ability to identify and react to task specific AOCs, including but not limited to, those that may occur at regulator stations.

5. If applicable, all work should be coordinated with the Control Room prior to and during taps, tie-ins, and retirements. Any abnormal SCADA readings should be investigated and rectified prior to proceeding to next steps.

6. The exact location, purpose, and functionality of all underground sensing line taps should be verified prior to performing taps, tie-ins, and retirements.

7. Identify the location(s) of valves that will be required to be used in an emergency situation. Verify that they are operational.

8. Identify and review all working monitor regulator stations and determine if the installation and use of full capacity relief valves at the station would optimize safety. (Is there a single event or series of events that can render the overpressure protection ineffective?).

Thank you for your attention to this matter. It is imperative that the above best practices are reviewed by your company so that we can continue to ensure that Georgia's natural gas systems remain safe and reliable. In addition to the steps above, I ask that you review your gas emergency practices and remind you of the requirement to offer annual training to volunteer fire departments regarding the appropriate response to gas related emergencies, and to police departments regarding the recognition of gas related emergencies. If you have any questions I can be reached at michellet@psc.state.ga.us or at 404-656-2765.

American Gas Association

Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event

November 26, 2018

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The purpose of this document is to provide guidance to natural gas utilities on leading practices that may supplement current practices to reduce the possibility of an over-pressurization event, especially in a utilization pressure system. AGA's member companies are steadfastly dedicated to the continued delivery of natural gas in a safe and reliable fashion to the communities they serve. We are committed to sharing leading practices and lessons learned across our industry in order to enhance our collective performance.

Many of the leading practices described in this document are currently implemented at natural gas utilities but they are not uniformly applicable to all systems nor exclusive. This document contains practices above and beyond minimum federal regulations. Depending on each system's unique characteristics, it is the consensus of AGA members that appropriate implementation of the practices in this document may reduce the possibility of overpressurization. The determination of whether to adopt any of the items contained in this technical note is individual to each company, recognizing that not all practices will be applicable given the size, configuration, pressures, and other features of a particular system.

The need to implement every practice and the timing of any implementation of the practices described in this document will vary with each natural gas utility and the specific environment in which they operate. The actions within this document should be evaluated in light of each operator's system, geographic variables, the operator's independent integrity assessment, risk analysis and mitigation strategy and what has been deemed reasonable and prudent by their state regulators. Therefore, not all of the practices described in this document will be applicable to all operators. As used herein, the term "should" is not mandatory but is to be acted upon as appropriate.

This document is intended to serve as a technical resource for natural gas operators. Note that the appendix is an excerpt from an AGA publication which contains additional background information and practices which address overpressure protection and the related topic of system regulation.

Since the scope of this document is limited and primarily focused on practices to further reduce the possibility of an over-pressurization event, it does not identify leading practices in other areas, including emergency response. The reader should not conclude that the AGA members believe these are unimportant issues.

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Contents

Section 1: Design of Distribution Systems and Regulator Stations

Background of Natural Gas Systems

Natural gas utilities provide service to residential, commercial, and industrial customers. The typical source of the utility's gas supply comes from pipelines that operate at a high pressure. The high elevated pressure allows the gas supply to travel many miles underground throughout the country. For delivery to residential, commercial, and industrial customers, the pressure must be reduced to a lower pressure level that the customer can receive.

The gas industry has used pressure regulators to reduce pressure since the 1800s. The primary function of a pressure regulator is to maintain constant, reduced pressure at the outlet. This is accomplished by varying the regulator's position/opening such that the flow of gas through the regulator station matches the demand on the downstream system. As system demand decreases, the flow through the regulator decreases as the regulator responds to the increase in pressure in the system. Conversely, as system demand increases, the regulator flow must also increase (otherwise the system may run out of supply). The types of gas regulators available for selection by the gas industry range in size depending on the system demand being supplied. Despite their diverse sizes, they can be categorized according to application: appliance, service, industrial, and distribution/transmission systems. Just as there are many regulator choices there are also multiple points where regulators are used for pressure reduction. Common design points include city gate stations, district regulator stations, farm taps, industrial customers and residential customers.

City gate stations are a primary pressure reduction point for the high-pressure pipelines that transfer gas to distribution systems. The basic function of these stations is to link high-pressure transmission pipelines to distribution pipe systems. A city gate station usually performs three primary functions:

1. It reduces the pipeline pressure to operating pressure of the utility pipe system.
2. It measures the volume of gas delivered to the utility.
3. Odorant is added to the natural gas to enable the detection of gas.

District regulator (DR) stations are pressure-reducing facilities downstream of city gate stations that reduce the pressure in the pipeline coming from the city gate to a lower pressure. This lower pressure downstream of a DR is more suitable for providing service to customers or other distribution networks within the LDC's distribution system. The operating pressure of the distribution systems upstream of district regulator stations vary depending on the distribution systems configuration and downstream demands. The pressure of the distribution systems downstream of these DR stations usually vary from about 100 pounds per square inch gauge (psig) to as low as 0.25 psig. These downstream pressures may be categorized as high, medium, or low-pressure distribution networks. Although classification of pipe networks by pressure level is common, terminology and the pressure range covered by each class varies between utility operators and systems. System pressures are affected by a service area's demand with respect to customer usage needs, weather considerations, design loads, and other maintenance requirements.

High pressure networks offer service to residential customers either directly or by means of a medium or low-pressure distribution networks. Whenever gas is fed from a network operated at a higher pressure to one operated at a lower pressure, a pressure regulator is installed between the two points. A pressure regulator will reduce the higher pressure of incoming gas to lower pressure of outgoing gas.

The design criteria for each system are unique, leading to different designs for each regulator station. Some examples of factors that cause variations in regulator station design include:

- Maximum and minimum flow requirements based on the customers demand
- Upstream and downstream maximum allowable operating pressure (MAOP)
- Forecasted future flow requirements
- Maximum and minimum pressures available from the upstream system
- Number of stages for pressure reduction
- Number of supply inputs - fed by single or multiple supply lines
- Gas temperature and gas quality
- Location and environmental conditions, driven by local ordinances
- Amount of land or area available for the station to be built
- Gas contaminants (such as sulfur, liquids and particulate debris)
- Proximity to highly populated areas

Station design aspects that vary include:

- Type of regulator(s) or control valves installed
- Above Ground versus Below Ground
- The quantity of regulators installed
- Location of downstream pressure sensing points
- Type of over-pressure protection installed
- Use of heaters
- Equipment to remove contaminants from the gas stream
- Equipment to allow remote control of pressure settings
- Use of odorizers

Distribution systems are designed to provide safe, efficient, and reliable service to the customer. Customer fuel lines operate at low pressure to ensure proper appliance performance, typically less than 1 psig. A lower pressure system that delivers gas at minimum delivery pressure is sometimes referred to as a utilization pressure system. Consequently, it is not necessary to install a service regulator to reduce pressure for each customer when the system operates at utilization pressure.

Operating a system designed for minimum delivery pressure can be challenging as the needs of the system are dynamic and change with demand. Extreme cold weather days, customer demand changes, etc. require accurate pressure control. Utilization pressure systems have typically been designed as fully looped systems. Fully looped systems minimized customer outages by providing many alternative paths by which gas could reach the customer.

When a distribution system is designed at pressures higher than utilization, i.e., above the customers delivery pressure, service regulators are installed at the customer meter set to reduce and control the pressure to a uniform level to the customer.

The modern gas regulator is a highly reliable device; however, failures could potentially occur due to a number of reasons such as physical damage, equipment malfunction, and the presence of foreign material in the gas stream. The industry has developed multiple layers of protection to mitigate the potential of over-pressurization. While there is no design standard that is applicable to all situations, some common over-pressure protection designs include:

- Use of in-line monitor regulators that control pressure upon failure of the primary control regulator.
- Use of relief devices that vent excess gas pressure to the atmosphere.
- Use of automatic-shutoff devices, such as positive shut off valves and fail close regulators to interrupt the supply of gas.
- Installation of filters and strainers to eliminate debris entering a regulator.
- Deployment of signaling devices that notify operating personnel of equipment failure or abnormal operating conditions (AOCs).
- Use of telemetry and transducers that are monitored remotely with corresponding alarm set points.

Customers on systems that operate at pressures higher than utilization system pressures have their own individual regulator located at the meter. Customers served from utilization systems do not require individual over-pressure protection because the entire distribution system operating at utilization pressure has over-pressure protection at the district regulator station or at another location. The basics of over-pressure protection requires the design to protect the downstream piping system from excessive pressure.

Design Practices For all Pressure Classifications

The following practices should be considered when designing new regulator stations, modifying existing stations, or selecting over-pressure protection. System, environmental, and other factors unique to each operator will determine the applicability of each practice:

1. *Practice: Include pressure monitoring and alarm functionality within designs of systems and formalize approval via a Management of Change (MOC) process.*
   Description: Design for a mechanism to generate an alarm condition. Mechanisms may include: alarm relief (“whistle”, “tattle-tale”, “token”), full relief valves, pressure recording devices, pressure signals to Gas Control, etc. Critical pressure points should be capable of alarming or generating a real time notification (relief, whistle, token alarm to Gas Control or Operations, etc.) when an AOC occurs. Safety sensitive pressure monitoring points should be

field verified via the communications network to Gas Control. Field equipment should be calibrated and inspected to confirm alarm set points are properly configured to trigger at the appropriate upper and lower limits. Consider any modifications to critical regulators, pressure monitoring points and overpressure devices be validated through a formal MOC process.

2. *Practice: Design stations with remotely controlled valves and regulators.*
   Description: When designing new systems consider remotely controlled valves and regulators which may aid in the quick isolation of critical stations, where appropriate.

3. *Design for Response Time.*
   Description: When using monitor control valves and slam shut valves, recognize the inherent time to respond/time to close to enable adequate response. Equipment set points and operational characteristics should be taken into consideration.

4. *Practice: Size over-pressure equipment to current load and monitor for future load needs.*
   Description: Primary regulators, monitor regulators and relief valves must be sized and designed to enable adequate over-pressure protection. Parameters which dictate proper sizing, such as system demand requirements, must be evaluated. All station equipment must be designed to operate within its intended operating range. Periodically contact industrial customers to verify gas usage to understand if load patterns have changed, or if a significant change to their future load profile is anticipated. In completing this practice, operators should confirm system equipment is sized appropriately to deliver load and gas pressure safely.

5. *Practice: Design sensing lines to be protected and located close to or inside the regulator station.*
   Description: Sensing lines should be sized appropriately for the regulator and account for restrictions (i.e., reduced port ball valves, needle valves). Each regulator and relief valve shall have an individual sensing line, per 49 CFR Part 192 regulations. Sensing line taps should be located within the station side of isolation valves, and as close to the station as possible. If underground, route the sensing lines for supply regulators and over pressure protective devices to different locations to minimize the possibility of multiple lines being damaged by an excavation.

6. *Practice: Mitigate the possibility that a common mode of failure, or a single event, could take out the primary ("worker") and the monitor regulators.*
   Description: Single events can impact the primary and backup regulator. Determine what can be done to reduce the possibility that any single event can disrupt both regulators.

7. *Practice: Install slam shut valves, where practicable*
   Description: Installing slam shut valves is an option for over-pressure protection and loss of sensing pressure and maybe effective for additional system protection. Slam shut valves may be considered, particularly in systems where multiple regulator stations supply gas to an area.

8. *Practice: Create standard regulator station design templates that are approved by a licensed professional engineer or engineer with equivalent experience and technical knowledge.*
   Description: Establish standard designs for regulator stations. Require that any deviation from the standard should be approved through a design management of change (MOC) process that has been reviewed and approved by a licensed, professional engineer (PE) or engineer with equivalent experience and technical knowledge.

9. *Practice: Add or improve remote controls of stations and valves.*
   Description: Consider designing critical systems, including regulator stations, to be monitored and controlled remotely, or by a Gas Control room via a SCADA system.

10. *Practice: Design for atmospheric vent lines to be unobstructed for proper venting.*
    Description: In cases where vent lines are designed with below ground regulators, separate lines should be installed for each piece of control equipment and terminate so they are not impacted by water infiltration into the vault. Above ground facilities should be vented to avoid the impact of insects, ice, and environmental forces. Confirm that all vent lines are secured from motion or vibration.

11. *Practice: Above ground regulator sets and other critical regulator station equipment should be protected from vehicular and pedestrian damage.*
    Description: Bollards should be properly sized and installed to protect regulators from any potential vehicular traffic. Other considerations for protection include: locked fences around regulator stations, locked bypass valves, weather protection, and added protection for control lines from damage.

12. *Practice: Design for station security.*
    Description: Critical station valves should be designed with locking devices, as needed, so they can be locked in their normal operating position.

13. *Practice: Design bypass valve configurations for secure operation at stations.*
    Description: Two bypass valves should be considered in series to enable quick control if one valve fails during operation. To prevent unintentional operation, locking mechanisms should be installed on the valves when not in use. Consider locating bypass valves at a distance from operating equipment to confirm safe accessibility and operability in an abnormal operating condition, i.e. Fire Scenarios.

14. *Practice: Enhance regulator station design requirements in areas with a history of contaminants in the gas stream.*
    Description: Contaminants can impact pressure regulation equipment operation. Consider installation of a properly sized separator to remove rust, dust, liquids, or debris upstream of the regulator station. Consider installing heaters to reduce potential for freeze-ups and sulfur filters on pilot-operated regulation equipment in areas with known sulfur issues.

15. *Practice: Confirm flow path to relief valves are not compromised.*
    Description: Steps should be taken to not compromise the flow path to a system relief valve during construction (abandonments, new construction, reconfigurations, and renewals).

16. *Practice: Emerging technologies are monitored by the industry and should be considered in future over-pressure designs.*
    Description: When technology develops operators should consider, where feasible, to integrate new technologies that may enhance over-pressure protection.

Additional Design Practices for Utilization Pressure (i.e. low pressure "LP") Systems

In addition to the above, the following practices are options for operators to consider implementing, depending on the uniqueness of their LP system and the local environment.

1. *Practice: Design additional over-pressure protection on utilization pressure systems, where feasible.*
   Description: Consider adding additional layer(s) of protection for over-pressure protection. Design could include an operator, monitor, slam shut, full capacity relief valve, or a customer service regulator, where feasible.

   Consider utilizing relief devices throughout the system, particularly in a utilization pressure system fed exclusively by primary/monitor stations. This is an additional control to mitigate the potential for over-pressuring a system and also acts as an alarm. Urban environments may add additional complexity to finding a suitable location for the relief valve blow down stack. Locations can be at the regulator station or a distance downstream of the station.

2. *Practice: Design for new or replacement low pressure and utilization pressure district regulator stations to include pressure monitoring.*
   Description: Where practical, design the system so there is pressure monitoring of all utilization pressure stations and systems.

Section 2: Operating Procedures and Practices

This section includes guidance on Operational Procedures, Practices, and Standards that enhance the reliability and safety of natural gas systems affecting System Regulation, Regulator Station Design, and Overpressure Protection. It is the operator's responsibility to implement procedures and practices such that its natural gas systems are operated and maintained in a safe manner. Such practices may include, but are not limited to, the items in this section.

Regular maintenance for regulator stations

Regular inspections and maintenance activities can help determine that equipment in pressure reduction stations is working properly. The frequency of station inspections over and above regulatory requirements should be based on the following:

- The type of station (e.g., City Gate, District, Customer Sales, etc.)
- The type of equipment at the regulator station (i.e. remote monitoring)
- The configuration and number of the regulator runs at the station
- The style of regulators used (e.g., self-operated, spring-loaded, boot-style, pilot-loaded, pilot-unloaded)
- Whether the regulator is above or below-grade
- Historical performance of a particular regulator or station
- Gas quality
- System or sub-system throughput
- The amount of pressure cut, or differential, across the regulator station

Some of the regular maintenance activities performed on a station may include:

- Visual inspection of the station to identify risks and/or concerns that may have arisen since the last inspection
- Equipment functional inspections and calibrations
- Regulator operational inspections (visual inspection, check for regulator lock-up)
- Regulator maintenance inspections (regulator tear-down, inspection, cleaning, replacement of soft goods, filter inspection or replacement)
- Annual leak survey
- SCADA field electronic sensing equipment point-to-point verifications

System Monitoring

Strategically placed telemetry equipment monitors key parameters to assist with maintaining safe and reliable service. Telemetry systems include measuring instruments or detectors, a medium to transmit data, a receiver, and a system that records/displays data. If system control equipment is in place, an operator's Gas Control group monitors the data received, and either acts upon any alarms by making remote adjustments, or dispatches field personnel to investigate issues. Stand-alone electronic pressure recorders can also alert of an overpressure or under-pressure situation. If an operator has a SCADA system in place, these recorders can be programmed to send an alarm to Gas Control whenever system pressures fall outside acceptable levels. Operations personnel can be dispatched to investigate the problem.

Records

Complete records and drawings should be retained and documented on any work related to gas regulation or overpressure equipment, in accordance with the operator's records retention policy. This includes the location of all taps, control lines, and vent lines. As practical, records and drawings should include accurate dimensions and notations of as-installed conditions. Operators should consider having a system in place to make this information readily available to any field personnel who may need it, such as locating technicians. Mapping of all gas systems enables proper planning of system upgrade activities and maintenance. System interconnection points, pressure reduction stations and valves should be included in records.

Damage Prevention

Operators should work with their local One Call Center(s) to screen dig tickets that are in the vicinity of system gas regulation or overpressure equipment. Locates performed near system gas regulation or overpressure equipment should include marking the location of all taps, control lines, and vent lines. In addition, operators should consider monitoring excavation activity in the immediate vicinity of buried control lines and take necessary actions to protect them from damage.

Construction and Work Permitting Process

Operators should put in place processes and job-specific procedures for any planned work that could result in a significant interruption of gas flow to the network, require significant internal/external resource coordination activities, and/or involve multiple coordinated procedures. Procedures should identify all stakeholders when work is done on gas regulation or overpressure equipment that could cause adverse effects.

Tie-ins and Uprates

Tie in connections between two segments of natural gas piping typically take place between an existing pipeline and a newly installed pipeline, and often as part of Replacement/ Modernization Programs. During any tie-in procedure, pipeline pressures on both sides of the tie-in point should be monitored to:

- Maintain the pressure in the pipelines where the flow of gas is stopped;
- Prevent connecting mains with different operating pressures and MAOPs; and
- Verify that mains being connected are the ones intended to be connected to (not abandoned or operating at a different pressure)

Additional precautions should be taken when any work is done on or near system regulators and overpressure equipment. Field personnel should have a clear understanding of the impact that their work could have on a gas system, especially when working on utilization pressure systems where customers do not have secondary pressure regulation. Tie-ins and uprates should be done in a controlled manner where all departments, including Gas Control, are communicating as work is being performed. Decision points (go/no go) in the procedure should be identified and clearly communicated prior to initiating the pressure increase.

Standard Operations and Maintenance Practices

1. *Practice: Create and follow written procedures.*
   Description: Written procedures aid in successful execution of tasks and processes in projects. Common procedures should be standardized and included in the Operations Manual. Written procedures should be present or accessible from the job site. Complex work should be reviewed before being issued to the field, by all departments involved in the project. For example, when applicable, Engineering, Operations (contractors when appropriate), and Gas Control should review the procedures. In complex projects, a checklist can function as a written procedure. A process for approving field changes to a procedure should be specified. Operators should consider requiring review and approval of complex procedures by a licensed professional engineer (PE) or engineer with equivalent experience and technical knowledge.

   Procedures should contain the necessary steps in proper order to be completed prior to beginning field work (such as verification of accessibility of valves and their position, below ground fittings, all isolation points, and operating conditions of the system, etc.). System designations and operating pressures should be in the procedures to ensure recognition of over or under pressure event. Restrictions or AOC's that alter a procedure (weather, generation load, etc.) should be accounted for and a process for approving field changes should be specified. Refer to section (D) of this section for records retention.

2. *Practice: Use appropriate personnel and equipment to monitor pressures during work.*
   Description: Use calibrated gauges, of the type and pressure range suitable for the system being worked on and continuously observe in appropriate locations to monitor the operating pressures of the system during any activity that could potentially cause over-pressurization. Leave gauges on for an appropriate length of time after the work is completed, to identify any lagging pressure changes. Consider the use of qualified pressure control personnel to monitor the operation of regulator stations within the scope of work.

3. *Practice: Consider eliminating direct connections between systems operating at different pressures.*
   Description: If this configuration is part of emergency pressure support of a system, the valves should be labeled, locked out/tagged out, and clearly identified on all maps. Consider adding gauge connections on both sides of these valves. Prevent operating a valve that connects a higher pressure system to a lower pressure system, especially a utilization pressure system.

4. *Practice: Lock and tag all bypass valves.*
   Description: Regulator station bypass valves should be locked and tagged to prevent unintended or unauthorized operation resulting in an AOC. Provide security around bypass valves if unlocked. Consider a special valve key or valve cover preventing anyone other than qualified staff from operating a regulator station bypass valve. The need for locking devices should be balanced with the weather and environmental conditions of the area and the

impact on emergency response. Consider implementing a formal Lock-out Tag-out (LOTO) program to expressly spell out when LOTO is required and how it protects the operator from overpressure events.

5. *Practice: Exercise critical valves prior to initiating a procedure.*
   Description: Operations personnel should confirm location of all valves that are critical to isolation of a work area or a pre-determined valve isolation plan. Operator should exercise critical valves to verify that they are operable. Confirm that the critical valves can be operated, while monitoring system pressures on both sides of the critical valve. See Practice 2 above regarding pressure monitoring and use of gauges while operating valves.

6. *Practice: Written procedures should include AOCs.*
   Description: The expected range of pressures during the procedure, as well as the MAOP of the system should be communicated to personnel in the field and control room, if the utility has a gas control. Actions to take in response to abnormal pressures should also be communicated. Field personnel should verify the pressure and/or flows measured in the field are the same as what the Gas System Controller is observing in the control room, when applicable. Emergency contact information for gas company personnel and emergency first responders should be available/accessible to everyone on the job site.

7. *Practice: Develop a standard written procedure for notifying emergency first responders and provide clear instructions on relief devices.*
   Description: Both Dispatch and Gas Control operators should use the same set procedure to notify emergency first responder personnel when there is an AOC. If the notification is to inform first responders that a relief valve is blowing, the caller should also inform them that the equipment is operating as designed, and that the relief device should be allowed to continue relieving pressure.

8. *Practice: Pre-job briefing (tailboard meeting) to review procedure before beginning.*
   Description: A briefing with Operations personnel performing the work should be held. Updates to the job briefing should occur based on changing conditions (weather changes, shift changes for employees, transitioning between day shift and night shift, significant delays between start and finish of procedure, etc.) Identify scope of work involved and involve Gas Control, if applicable, when the procedure will result in a significant change in system pressures or when over-pressurization is a threat. Verify SCADA equipment that is being used as flow/pressure monitoring is properly communicating to control room on the day of work being performed.

9. *Practice: Data refresh rate awareness and timeliness.*
   Description: During standard operations or procedures, Gas Control should be aware of how often SCADA sites are polled, and adjust responses accordingly. When possible, consider increasing frequency of polling on systems where active work is being performed on facilities considered to be critical, to set an appropriate time between readings.

10. *Practice: Planned maintenance work should be communicated to Gas Control.*
    Description: For systems that have a Gas Control, consider establishing communication protocols based on the significance and potential impact the maintenance work may have on field and control room operations.

11. *Practice: Maintain awareness of activities in the upstream system to confirm system changes or work performed has not compromised pressure regulation equipment.*
    Description: Operators should consider a means to minimize the potential for fluid and debris to enter the gas stream and perform inspections after work is performed upstream of a regulator station, as needed, to mitigate the potential impact of any debris or liquids that entered the regulator station. For example, transmission in-line inspections may dislodge scale and debris which could travel downstream into regulator stations.

Construction, Tie-Ins, Tapping, Uprates, and Abandonments Practices

1. *Practice: All regulator control lines and service lines to structures in the area of excavation work should be located.*
   Description: The written procedure and the locate markings should indicate if the lines are connected to the main being worked on. Structures at street intersections and main crossings are particularly vulnerable. Pressure regulator control lines within the excavation area should be exposed by hand or with soft-dig excavation equipment and protected during excavation. Facilities that were incorrectly mapped or unmapped should be documented and communicated to the appropriate group to be added to the map or corrected.

2. *Practice: Prior to an uprate operation, evaluate the location and placement of any pressure regulator equipment, control lines, and relief valves in regards to the uprate strategy/plan.*
   Description: An uprate procedure is a detailed process to change the MAOP of a system to a higher pressure based on system design, construction and pressure test. The procedure should include a review of the existing regulator stations to determine if their locations are acceptable and the installation meets system demands and company standards. A review of the operating history of the regulator station should also be conducted, where applicable. The results of the review and any changes, modifications or new installations should be included in the procedure and appropriately sequenced. Operators should require review and approval of system uprates by a licensed professional engineer (PE) or engineer with equivalent experience and technical knowledge.

3. *Practice: Simplify complex procedures by breaking into multiple, less complex procedures.*
   Description: Considerations should be included during project planning to maintain manageable scope of work activities and procedures. Complex projects with numerous tie-ins or other involved work activities could be broken into multiple manageable procedures to reduce risk of unforeseen abnormal conditions.

4. *Practice: Work-in-Progress and Work-in-Planning notations ("clouds") on maps.*
   Description: Construction planners should identify and notify all affected departments of planned construction activity. A drawing should be provided to visually identify all impacted work areas across multiple departments or service areas. This can prevent separate groups from performing work on the same, or related systems and creating operational issues.

Damage Prevention Practices

A serious threat to the integrity of a natural gas facility is the possible damage resulting from excavation, external forces, or pedestrians around piping and regulator stations. Damage to the piping near a regulator or the control lines of a regulator can cause an AOC (abnormal operating conditions), sending high pressure gas downstream. Below are some of the practices in which the threat of such damage may be mitigated.

1. *Practice: Establish buffer around the regulator station for One Call tickets.*
   Description: All one call tickets should be reviewed to determine location and prioritized if near a regulator station. Consider a set perimeter for prioritization such as "within X feet" of a station. Extra precaution should be taken in these areas, and procedures should be developed to reflect the extra actions to be taken by inspectors, personnel observing 2nd and 3rd party excavations, field operations personnel, etc. The benefits of technology, such as GIS, should be considered to recognize these buffer zones, potentially automating the prioritization of one call tickets

2. *Practice: Have operator personnel on site observing 2nd or 3rd party excavation activities in close proximity to regulator stations or mains with buried control lines.*
   Description: Operators should consider having qualified personnel monitoring construction within the specified buffer zone around regulator stations with buried control lines. This provides trained response to abnormal conditions that may occur during the work, including stop work authority. This person should conduct pre-construction meeting with the 2nd or 3rd-party construction crew prior to any work being performed to explain the importance of avoiding any damage. The excavator should hand dig or use another form of soft digging technology when digging around a regulator station. Consider shutting-in stations, when possible, or putting them on local control.

3. *Practice: When working in the vicinity of regulator stations and utilization pressure systems, create a process to identify potential AOCs.*
   Description: Operator should provide field personnel with a standardized checklist that covers threats that could cause an AOC. Confirm the checklist is used prior to performing work.

4. *Practice: Locate and maintain marks for buried control (sensing) lines.*
   Description: Locate and mark all buried control lines and associated piping. Hand dig or use soft dig technology to excavate around control lines. Consider installing above ground signage, below grade protection plates and/or marker balls to indicate buried gas utility piping below to increase awareness.

5. *Practice: Protection of control lines at regulator stations.*
   Description: Measures to protect control lines include installing with hard pipe or heavy wall stainless steel tubing, or locking or securing by some other means such as taking off valve handles, and eliminating the ability to shut a control line valve without a wrench.

Records Practices

Records are critical for operations, maintenance, risk identification, and analysis. Operators should have a documented process for creation, collection, identification, distribution, and storage of records. The process should identify authority and responsibility for managing records.

1. *Practice: Use maps and records on site to complete work*
   Description: Utilize appropriate maps, records, and construction drawings to complete work as designed. Perform a mapping system review in coordination with the applicable personnel, such as representatives from engineering, pressure control, and gas control, when applicable, to validate and update that control line and pressure sensor locations are shown in the mapping system as needed. Utilize records and maps of all interconnects and regulator stations feeding into a given system. Regulator Station drawings should be field verified for control line locations and be available to company personnel onsite at the station. If station operation is part of the procedure, a drawing of the station should also be a part of the work package. Control point locations should be accurate and updated during any field working procedure. Verify accessible valves and their position (normally open are open, etc.), below ground fittings, and operating conditions of the system should be performed as needed. All gas supply interconnects and location of company owned facilities need to be mapped or in written form.

2. *Practice: Implement a Records Management System*
   Description: Records management systems can track equipment in the system, as well as maintenance records of the equipment. Consider a system that can notify the responsible parties in advance of maintenance schedules for pending work.

3. *Practice: Management of separation valves.*
   Description: Valves that separate systems operating at different pressures should be eliminated, where possible, as noted under Standard Operations and Maintenance Practices, Practice 3. If it is not possible to eliminate separation valves, they should be clearly indicated both on system maps and in the field. *This practice is <u>not</u> applicable for station bypass valves.*

4. *Practice: Labels for critical valves should indicate the direction to open/close and number of turns to full open or full closed.*
   Description: Asset labeling in the field should include not only the critical valve number as shown in the record management system and on maps and station drawings, but also indicate which direction the handle or wheel should be turned to open and close the critical valve,

and the number of turns to move the critical valve from full open to full closed. Alternatively, this information may be provided to field personnel via electronic devices.

5. *Practice: Collect and maintain precise location data for equipment, sensors, critical valves, and control lines, where possible.*
   Description: When field personnel are performing maintenance on equipment in the field, consider taking GPS readings or precise measurements. Include in records for all pressure sensors, regulators, critical valves, and control lines.

6. *Practice: Complete and retain the as-built drawing for the installation or reconfigurations of pressure regulation assets in a timely fashion.*
   Description: Upon completion of pressure regulation asset installations or reconfigurations, field mark-ups should be verified and updated into a records system for all assets related to pressure regulation.

Section 3: Human Factors

Understanding and addressing human factors is critical to reducing the frequency and severity of pipeline incidents caused by over-pressurization. Considerations include:

- Promote a positive pipeline safety culture, which influences the attitudes of employees and contractors regarding pipeline safety and drives a conscious effort to reduce the risk of over-pressurization.
- Identify and communicate to all personnel safety-critical tasks for each project and system operation tasks that may result in over-pressurization if procedures are not followed. Encourage use of error prevention tools such as 3-way communication.
- Identify all personnel performing the task are qualified for the task.
- Identify AOCs and the appropriate actions to be taken should they occur by involving construction, operations, gas/pressure control, and design personnel.
- Identify where human failures have a high likelihood of occurring during each step of a task and determine measures to prevent or mitigate the likelihood of over-pressurization occurrence.
- Wherever possible, design the system to account for the possibility of human failure as discussed in Sections 1 & 2, minimizing the potential for human error in the operation or maintenance of the system.

Management of Change (MOC)

MOC process is a leading practice for evaluating and mitigating the risk of significant changes to a pipeline system. Operators should consider developing a MOC process for all plans that have a potential for over-pressurization. The process should communicate the level of authority required to make changes to the design and/or written project plan. For example, inspectors and/or operator personnel may have authority to make certain types of field changes, while more complex changes may have to be approved by a licensed PE or engineer with equivalent experience and technical knowledge.

Training for Prevention and Recognition of Abnormal Operating Conditions

The training of operator and contractor personnel for executing construction, operation, and maintenance activities is essential. Personnel should be well-trained to perform their assigned duties. Prior to the start of construction, the operator must determine the knowledge level and skill set required to perform covered tasks. It is the responsibility of the operator to verify that personnel are qualified and have the knowledge skills and ability to perform each task assigned to them. Each employee or contractor must demonstrate a fundamental knowledge of performing the task including recognizing AOCs involving over-pressurization of a system along with possessing the technical and operational experience required to perform the work safely.

Due to the unique operating characteristics of a utilization pressure system, gas utility, contractor, and inspector personnel should have additional training on the different operating characteristics of a utilization pressure system. Gas utility and contractor personnel must be trained on how to recognize AOCs and what responses are required to mitigate or minimize their impact. AOCs associated with operating a utilization pressure system should be identified and operational actions defined to address these AOCs. In addition, design and gas control personnel should consider specific training on the operating characteristics of a utilization pressure system and the importance of ensuring the accuracy of the plans and documentation of all proposed work such as tie-ins, abandonments, critical operating valves, regulator stations, regulator station sensing lines, location and adequacy of over pressure equipment, uprating procedures, proper operation of SCADA system, response to SCADA alarms, and the identification of AOCs. When necessary, design personnel should make field visits to determine the accuracy of maps, as built documentation, location of critical infrastructures including regulator sensing lines, and SCADA locations as part of the project design.

Designing a safe, reliable, and efficient gas delivery system requires system knowledge and expertise. Some gas utilities require a licensed PE or engineer with equivalent experience and technical knowledge to design regulator stations and over-pressure equipment.

Operator Qualification (OQ)

An essential part of the work planning process is the identification of all covered tasks prior to the project commencing. Only qualified individuals or a person under the direct span of control of a qualified individual (when allowed) can be assigned a covered task. As part of the work plan, the covered tasks should be identified for each step of the process and incorporated into the work plan.

During the construction phase, the inspector(s) or company representative(s) must be fully aware of the operator qualifications of all individuals' including those who are performing a task without supervision and those who will be required to perform tasks under direct line of sight observation of another qualified individual. Anytime there is a change in personnel on the construction crew, or the procedures change, the operator qualifications should be re-verified.

Field Oversight

Field oversight including inspection, quality control and quality assurance measures of qualified personnel should be considered throughout construction, maintenance and operations processes. The level of inspection is specified by company policy and includes additional provisions for more complex projects and/or work tasks.

It is the operator's responsibility to provide documented procedures for qualified personnel detailing the step by step guide that directs them through a pressure system control work task. Field oversight activities can help with the understanding and execution of documented procedures during natural gas construction and operations, especially when the work sequence of events is extremely important and adherence to the documented procedure is critical to prevent over-pressurization of the system. For instance, field oversight can prevent a critical step or steps from being missed or not performed in the correct sequence, avoiding an abnormal operating event that could adversely affect the safety of the system.

All documented procedures and qualifications should be present on the job site or accessible per electronic means. For job specific procedures the person or person(s) in charge should be noted on the procedure or job briefing form. In addition, emergency contact information should be included for additional personnel, if needed.

Prior to starting construction, all appropriate personnel should meet to review construction drawings, contract specifications, design criteria, schedule, critical task list and task assignments, and OQ qualifications, and review AOCs to verify that all personnel are using the most current construction documents.

Management of Change Practices

As noted above, MOC is a formal procedure used to identify and consider the impact of changes to pipeline systems and their integrity. Management of change shall address technical, physical, procedural, and organizational changes to the system. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

1. *Practice: MOC process should govern proposed job changes during the construction phase, including appropriate approvals, signoffs, and communications on projects that have a potential for an over-pressure event.*
   Description: The MOC process should address the level of authority required to make changes to the design and/or written project plan. These procedures should be understood by the personnel using them and should address technical, physical, procedural, and organizational changes to the project.

2. *Practice: Clear delineation of authority during system work*
   Description: Delineation of authority should be clearly stated in the plan by including the critical task and the operator personnel responsible for approvals.

3. *Practice: Stop Work Authority must be granted to all personnel*
   Description: Each employee should be granted the accountability and responsibility to halt work not conforming to specifications, OQ qualifications, proper/safe construction methods, and specified job tasks.

4. *Practice: Operators should endeavor to collect and report near miss information and encourage the sharing of safety-related events.*
   Description: Operators should view near misses as learning and development opportunities. Near-miss incident investigations provide opportunities to implement new or revised procedures and address deficiencies and prevent similar events from recurring.

Training for Prevention and Recognition of AOCs Practices

Personnel must be sufficiently trained to recognize and react to AOCs during routine and construction work. Operators should consider utilizing the following practices to respond to AOCs:

1. *Practice: Train gas operations personnel on what occurs in the structure during an over-pressure event, including the potential consequences of the event.*
   Description: Operator should define additional AOCs for utilization pressure systems. Field service personnel need to be trained on how to recognize and respond to these AOCs to mitigate or minimize the impact to customers.

2. *Practice: Provide specialized training for field personnel to highlight the unique characteristics of working on utilization pressure systems.*
   Description: Due to the unique operating characteristics of a utilization pressure system, operator, contractor and inspector personnel should have additional training on the operating characteristics and AOCs associated with utilization pressure systems.

3. *Practice: Provide formalized training for design personnel.*
   Description: If the utility operates a utilization system, both construction personnel and design personnel should be properly trained on utilization pressure systems and the importance of ensuring the accuracy of the documentation of all tie-ins, abandonments, critical valves, regulator stations, regulator station sensing lines, location, and adequacy of over-pressure equipment and uprating procedures.

4. *Practice: Enhance the current AOC OQ covered tasks to include over-pressurization.*
   Description: Operators must review their AOCs to verify over-pressure of all operating pressure systems are addressed and actions developed to minimize or mitigate the impact.

Field Oversight Practices

Coordination between construction, control rooms, and field personnel is critical to safety. Practices to enhance coordination are listed below:

1. *Practice: Coordinate and communicate work activities to all parties involved in the project prior to initiating the next step.*
   Description: Operators should incorporate a process where field operation activities are coordinated through Gas Control or similar group to verify there are no new issues or constraints impacting the ongoing work. Constraints/issues could include work being done in adjacent systems that could adversely impact the construction plan. (i.e. working on a regulator station; operating critical valves; taking a critical line out of service, etc.)

2. *Practice: Permission to proceed needs to be clearly established, and a defined person in charge must be known by all on the job.*
Description: Personnel responsible for clearing critical tasks should be identified and communicated to those involved on the job.

3. *Practice: Written procedures must be followed in the appropriate sequence.*
Description: Work step sequencing is extremely important and should be understood and followed by all personnel involved in the task. Doing work out of sequence may result in over-pressurization or other emergency conditions. Employees and contractors should be empowered to exercise Stop Work Authority, if the sequence of work is not followed.

4. *Practice: Require employees with system pressure expertise to attend design/construction planning meetings, including Gas Control and Operations personnel, when appropriate.*
Description: Operator work plans should include the various stages of the design approval. Each operator should determine when, during the design phase, Gas Control and Operations personnel should be included in the planning.

5. *Practice: Be prepared to rotate qualified staffing during lengthy procedures.*
Description: To prevent fatigue and comply with hours of service requirements, employees should be given rest breaks during lengthy procedures. A resource plan should be developed for long duration projects and incorporated into the project specific procedure. The resource plan may include details such as the number of qualified individuals necessary to complete the various steps in the procedure. Additional resources should be identified in the plan in the event the duration is longer than expected.

Section 4: Managing the Risk of an Over-pressurization Event

Distribution Integrity Management

Since 2011, natural gas distribution system operators are required to have a Distribution Integrity Management Program (DIMP) in place. DIMP programs confirm gas distribution system integrity by identifying system threats addressing risks these threats pose. The Gas Piping Technology Committee's (GPTC's) "*Guide for Gas Transmission, Distribution and Gathering Piping Systems*" contains a list of primary categories of threats and, of these, Equipment Failure and Incorrect Operations include factors which could lead to over-pressurization. Each system is unique so each operator must perform its own evaluation to identify the risk of over-pressurization to its system. Once identified and evaluated, the methods of mitigating the threat of over-pressurization include system design, modification of operating procedures, and additional personnel training. Earlier sections of this paper discuss these measures in detail. An operator's DIMP plan will not list all individual steps but should require that the programs and the person(s) responsible for that program are identified and included in the Operations & Maintenance plan. DIMP plans are dynamic in that they change as the system and conditions change and they must include the process for review and updating the plan.

In risk management terms, over-pressurization can be considered a low frequency event and consequence can vary from low to high, depending upon the design of the existing station and associated system. These types of events can be difficult to model due to the low number of data points. If an operator elects to consider over-pressurization as a threat, they should then estimate the consequence factor based on (1) an analysis of industry data, (2) a data-based calculation, and/or (3) Subject Matter Expert input. An operator may also elect to consider sub-threats of over-pressurization. For example, as part of a risk ranking model, low pressure cast iron may be assigned a higher risk score than one determined by leak history alone. For a system-wide risk model, regulator stations may be assigned a higher consequence score where they supply a utilization pressure system.

Should an operator determine that over-pressurization is a threat to their system, measuring the effectiveness of mitigation measures is very difficult for infrequent events and may involve reducing a frequency that is already extremely low or near zero. However, tracking and reporting identified improvements can show where potential gaps in the process are being addressed. Some examples of accelerated actions for incorrect operations from the GPTC guide are: improve procedures, improve training, evaluate locations where inadequate practices may have been used, and perform internal audits or inspections. Performance metrics can be applied to any of these.

The intent of the DIMP regulation is to allow an operator the flexibility to address its own system-specific threats. Cast iron, bare steel, and vintage plastic pipelines are a quantifiable risk and for gas utilities whose rates are set by their state, effective rate recovery mechanisms are in place for 43 states and the District of Columbia for replacement of vintage pipe, as of the publish date of this document. Mitigating the risk of over-pressurization should also be addressed through rate recovery mechanisms.

Support from stakeholders, communities, and customers

Many utilities are modernizing their distribution pipeline systems featuring utilization pressure. There is a significant amount of collaboration and support needed from various parties to upgrade these legacy systems to higher delivery pressures.

As an example, many customers resist moving their meters to an outside location. Relocation of the meter generally involves work that must be completed on the piping inside the home. In addition, some communities are considered historical districts, and resist the utility's efforts to move meters outside due to concerns with aesthetics or space limitations.

It is a leading practice for a gas utility to engage and secure the support of cities, towns, and counties in replacing utilization pressure systems. Streets and roads, along with other underground infrastructure, are greatly impacted by these upgrades. Gas utility operators and the communities they serve must work closely to develop plans that are workable for all stakeholders. Placement of pressure regulating stations and relief valves aboveground and/or in public right of way may need support by local communities to mitigate the risk of over-pressurization.

In addition, some utilities have worked with local public utility commissions to secure support for these types of issues in conjunction with a pre-approved rate recovery mechanism for infrastructure upgrades.

General Practices

The following general practices are options to be considered in managing the risk of an over-pressure event:

1. *Practice: A natural gas utility should look for opportunities to work with all stakeholders to pro-actively upgrade its utilization pressure systems.*
   Description: System pressure upgrades often require customer cooperation with moving meters outside and performing other work inside the home. In addition, support is typically needed from municipalities for installing pressure regulator facilities, particularly in historical districts. Effective cost recovery is needed to fund modernization of these gas systems. As cast iron and bare steel pipe are replaced, consider where it is feasible and practical to convert utilization pressure systems to higher pressure systems.

2. *Practice: Define risk criteria for overpressure events.*
   Description: Operators should track the number of overpressure events within their systems and evaluate for trends. Operators should conduct root cause evaluations or apparent cause evaluations for significant overpressure events.

Industry practices specific to DIMP:

1. *Practice: An operator's DIMP plan should incorporate existing programs and accelerated actions taken to reduce the risk of over-pressurization, if it is identified as a significant risk.*
   Description: Determine what actions and initiatives should be implemented to reduce the risk of over-pressurization, considering the probability of occurrence and the consequence of the event. This includes addressing human error or equipment failure that could result in an overpressure situation.

2. *Practice: An operator's DIMP plan should include the process used to identify performance issues that could involve a particular type of pressure regulator.*
   Description: The DIMP plan should include data collection and analysis that leads to identification of any performance issues for the makes/models of pressure regulators used in the system.

3. *Practice: In its DIMP plan, an operator should avoid using a probability of zero for low probability events and should consider their likelihood and consequence factors, or use Subject Matter Expert (SME) input.*
   Description: Events that have a low probability of occurring should not have a rating of zero in the risk ranking model used, unless supported by engineering analysis.

4. *Practice: In its DIMP plan, an operator should confirm the appropriate consequence factors are applied for low probability events, such as over-pressurization.*
   Description: Risk models used by operators should feature accurate potential consequence outcomes for those events that are tied to over-pressurization.

Glossary

Abnormal Operating Condition (AOC): A condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may (a) indicate a condition exceeding design limits; or (b) Result in a hazard(s) to persons, property, or the environment.

Bypass Valve: A valve used to control non-pressure regulated parallel piping runs within a pressure regulating station. A bypass valve allows for continuous gas flow if the regulating station is inoperable, taken out of service, or if additional gas flow is required downstream. Bypass piping is used to route gas around some part of a system or station (i.e. a regulator) to facilitate taking that part of the station out of service to be worked on.

Contaminant: Impurities including but not limited to rust, moisture, carbon dioxide, other liquids, debris, and sulfur compounds that are sometimes found in natural gas.

Control Line/Sensing Line (Control Piping): Piping that is connected to the regulator and downstream of the regulator. The control line increases or limits the flow of natural gas based on pressure measured downstream.

Control Point: A point in a gas system where pressure and/or flow is controlled. This may be a regulator station controlled by control lines connected to the downstream gas system, or controlled remotely from a Control Room.

Control Valve: Valves used to moderate and/or restrict the flow of natural gas. These valves can be actuated remotely, locally, or automatically by sensing pressure differentials.

Management of Change (MOC): Formal procedure used in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural, and organizational changes to the system, whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

MAOP: The maximum pressure at which a pipeline or segment of a pipeline may be operated.

Monitor Regulator (Monitoring Regulator): A pressure regulator installed in series with another pressure regulator that automatically assumes control of the pressure downstream of the station, in case that pressure exceeds a set maximum.

Primary Regulator (Worker Regulator): Pressure limiting and controlling device that reduces or limits the input pressure of gas to a desired set value at its output.

(Pressure) Relief Valve/Device: A pressure switch or unloading device that exhaust gas to atmosphere if pressure in pipe exceeds a set limit.

SCADA: Supervisory Control and Data Acquisition system is a computer-based system used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

Sensor: The initial device in a telemetry system that measures or senses a physical parameter (pressure, temperature, flow) and converts that into an electronic signal. Sensors may be connected to a transmitting device sending signals to a SCADA system, or they may be connected to a local device that logs or stores the information for uploading at a later date.

Separation Valve: Valves used to isolate gas systems, which may be operating at similar or differing pressures.

Slam Shut Valve: Valves specifically designed to protect downstream equipment from either under or over pressure conditions by immediately shutting off gas supply downstream if it detects the pressure drops or exceeds the permissible limit.

Subject Matter Expert (SME): Subject Matter Expert is a person or group of people who are trained and have adequate experience in a specific topic area to be considered to have expertise on the subject matter.

Utilization Pressure: A lower pressure system that delivers gas at a minimum delivery pressure needed to operate appliances.

Vent line: Vent lines provide a way to exhaust gas from the components and equipment to atmosphere.

APPENDIX: The following is taken from AGA's Gas Engineering and Operations Practices (GEOP) Series: Distribution System Design, Revised 2004, Book D-1, Volume III. The full document can be purchased at https://www.aga.org/news/publications-store/

Chapter 13

REGULATOR STATION DESIGN

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District regulator and city gate stations normally are required in a distribution system. They reduce the elevated pressures provided by a pipeline supplier to lower distribution system pressures. The city gate station, or town border station, receives gas at the supplier's elevated pressure and in turn serves individual customer meters and/or any district regulator stations at a lower pressure. The principles presented in this chapter can be applied to either type of station design. District regulator stations further reduce system pressures to levels beat suited to serve end-users.

CITY GATE STATIONS

A "city gate" or "town border" station is a multifunction station that usually includes pressure regulation, measurement, and odorization facilities. This is the transfer point between the pipeline supplier and the distribution utility. Normally, regulators are part of these stations because the pipeline supplier's system usually operates at a higher pressure than the utility company's system. At many stations, due to high pressure differentials, heaters are installed to warm the gas to compensate for the Joule-Thomson effect. In addition to regulation, the station usually includes metering facilities and equipment to measure the pressure and temperature of the gas and sometimes the specific gravity and heating value as well. Odorant injection commonly is performed at these stations. These stations usually are installed on private property owned by the supplier.

The flow metering and odorant injection requirements of a city gate station require special consideration by the design engineer, because they make this type of station different from the facilities normally encountered in a distribution system.

Flow metering is primarily the responsibility of the pipeline supplier, but distribution utilities monitor this measurement to verify billing, dispatch load as a means of remaining within daily contract volumes, and control odorant rejection. Although distributors sometimes install their own measurement facilities in or adjacent to the station, it is common practice for the distribution company to interface with the pipeline supplier's equipment rather than use separate metering facilities. In this way, the company and the supplier receive the same data on volume, inlet pressure, temperature, specific gravity, and heating value.

Odorization is usually the responsibility of the distribution utility. Although odorized gas may be received from the pipeline supplier, the level or type of odorant may not meet the needs of the distribution utility. Odorant should be injected at a point that will ensure good mixing at a rate proportional to gas flow. Special consideration should be given to the materials and assembly methods used in the odorant system to ensure compatibility with the odorant and to make the system as leak-proof as possible. More detailed information on gas ordorization can be obtained from the A.G.A. *Odorization Manual* and from the Institute of Gas Technology's most recent proceedings of its odorization symposia.[1, 2]

The engineer must be aware of any limitations to the flow rate at a gate station and design accordingly. The supplier may have a maximum flow limitation on its measurement equipment. The utility's operating system should not cause the system demand to exceed this limit because of the supplier's inability to measure the gas. Also, the utility must be able to react to a situation where no odorant is being injected into the flowing gas stream. By continuous monitoring, the utility can be appraised of this situation so that it can shut down the station, if feasible, until the problem is resolved. More detailed information on the selection and design of city gate station equipment is given in GEOP series Volume IV, "Measurement" and part of A.G.A Gas Measurement manual, "Design of Meter and Regulator Stations."

More than one supplier may serve a utility's distribution system through separate gate stations. In this situation, there may be targets set for the flow rate through one or more of the gate stations based on negotiated volume with each supplier. It may be necessary to design the regulators to function in a flow-control mode in addition to a pressure-control mode. Unlike a pressure control regulator, a flow control regulator responds to measured flow rate rather than to a measured downstream outlet pressure.

In distribution systems where flow control is used, pressure control regulation also must be used to pick up any variation in total system demand above the flow set point. The flow set point of a flow control regulator can be set higher than the total system demand. Therefore, a means of going into a pressure override mode must be considered in the design to prevent over-pressurization by the flow control regulator.

DISTRICT REGULATOR STATIONS

The district regulator station is a pressure-reducing facility that receives gas from a supply line and delivers it to a distribution system at a predetermined pressure and at a flow rate equal to (except for line pack) the demand on the system. Supply line pressures may vary from a few to hundreds of psig; controlled pressures in a distribution system usually vary from about 0.25 psig (1.7 kPa) to 100 psig (689 kPa). Distribution systems may be supplied by more than one district regulator station. Because of varying conditions and requirements, there are no standard designs that satisfy all situations. However, the following general requirements must be satisfied by all designs:

- **Performance**-The design must result in a district regulator station that will perform the function for which it was intended under all foreseeable operating conditions. Factors that will affect performance include proper sizing, equipment selection, piping layout, and sites selection.
- **Safety**-The design must provide protection against any possible damage or equipment failure that could result in overpressure and/or loss of supply to the distribution system.
- **Environmental**-The district regulator station should be designed to be aesthetically acceptable and free of objectionable noise and odour. The station must conform to all applicable codes and ordinances.
- **Economy**-The design must accomplish all of the above at the minimal overall project cost for initial installation and long-term maintenance.

DESIGN CRITERIA

The regulator station designer must determine the size of the installation in terms of performance, capacity, and equipment requirements. Factors to be considered are:

- Maximum and minimum flow requirements. Maximum flow usually occurs at minimum inlet pressure; minimum flow can occur at a variety of inlet pressures. Determination of maximum load can be developed from information such as:
  - ◊ Actual customer maximum hourly loads, including large commercial or industrial loads
  - ◊ Computerized network model
  - ◊ Capacity of the outlet main
  - ◊ Count of homes and heating customers

  Monthly sales data converted to maximum hour load
- Upstream and downstream MAOPs
- Future flow requirements. How much of the projected flow should be provided for the initial installation?
- Maximum and minimum pressures available in the supply line
- Number of stages of pressure reduction. If more than one stage is indicated, should the installation be a double cut or monitor design? How much distance is necessary between stages?
- Should parallel runs be provided or is a single run adequate? Are there other feeds into the distribution system? Would loss of this facility be critical to the system? If parallel runs are provided, should each be capable of supplying the system under maximum conditions? If a single run is adequate, should a bypass with or without a regulator be provided?
- Should a station bypass be provided? It is usually needed for single-run stations.

- Should heating be provided? If water or heavy hydrocarbon vapours are present in the gas and a large pressure reduction is required, the refrigeration effect may occasionally lower the gas temperature below its dew point with resulting hydrate formation. Low gas temperature also will freeze heavy, water-laden soil surrounding the outlet piping, causing heaving of foundations and road surfaces.
- Should the gas supply be odorized? Usually this is done at the city gate/town border station.
- Should noise control be provided in the design? Noise level restrictions in a residential area may influence equipment selection. Reduced noise trim on regulators, fences or below ground noise. Consideration should be given in design for noise protection to protect the general public and maintenance personnel. Vibration due to excessively high noise levels may cause instrument and mechanical failure. Special noise reduction regulator equipment should be considered when excessive noise levels are predicted by velocity calculations.
- Work space requirements. How much room is required for safe and efficient operation and maintenance?

SITE SELECTION

When general design requirements have been established, a suitable location can be selected. For a new system, the constraints on location may be quite flexible, for an existing system, the location is dictated by the whereabouts of the supply line and distribution system piping capable of carrying the required gas volume.

In rural or undeveloped areas, private land may be available for a nominal cost and, consequently, may be the choice for all except very small regulator stations. In urban areas where land is expensive and difficult to obtain, use of private land may need to be reserved for very large installations and/or those requiring above ground housing.

Installations requiring gas odorization or heating usually are located on private land. Installations on private land have the flexibility of being installed above ground in buildings, fenced, or unenclosed; alternatively, they may be installed in buried or partly buried vaults or pits. Pits usually are considered underground enclosures with manhole access, whereas vaults have steel or aluminium doors or removable covers through which access to the interior is gained. Covers should be designed so that they cannot accidentally close or fall into the vault or pit and damage the regulator equipment. Covers must be designed for anticipated vehicle loading.

Installations on public rights-of-way may be in buried vaults or pits if the water table and drainage permit; they also may be installed above ground without enclosures if protection from traffic and other damage is adequate and local authorities permit. (See Figure 142.)

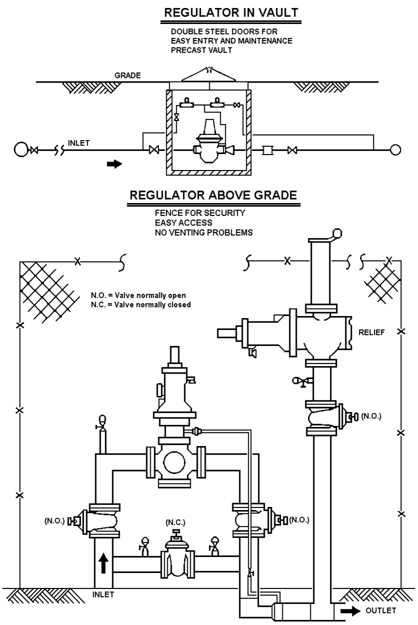

Figure 142. **Typical regulator installations - below grade *(top)* and above grade *(bottom)*.**

Acceptable screening for aesthetic reasons may also be necessary. Plastic strips can be threaded into chain link fences to screen station facilities from view, and, on occasion, above ground enclosures have been designed to blend with surrounding structures.

Preferably, vaults and pits should be located out of roadways if access will be a problem because of traffic congestion or parking. Underground enclosures constructed of concrete or steel under roadways in northern snow areas are subject to the adverse effects of salt used for snow and ice removal; equipment and piping particularly are prone to corrosion. Vaults should not be located at low elevations or near catch basins where they are exposed to flooding unless the equipment is capable of operating safely underwater. Sidewalk locations in high, dry sites are preferred. Access to electric power must also be provided if the installation includes electronic components. Ventilation of vaults should be provided in accordance with applicable codes.

Above ground facilities have the advantage of relatively easy accessibility, low maintenance, and low cost. They have the disadvantages of possible damage from traffic and/or vandalism and a greater probability of there being a noise problem. Since they usually must be installed on private property, they may also require land acquisition and possible rezoning.

REGULATOR SELECTION

The regulator is the heart of the regulator station and should be chosen with care from the wide variety of designs available. Basically, a regulator consists of a control valve that controls gas flow, a sensing element and a loading element. Refer to Chapter 11 for descriptions of the various types of regulators.

Factors that should be considered in selecting the type of regulator include:

- Outlet pressure droop characteristics and response
- The maximum and minimum pressure differential rating of the equipment
- Reliability of operation
- Ease of maintenance (in-line maintenance is advantageous)
- Cost of equipment
- Physical space limitations in vaults
- Noise characteristics

REGULATOR SIZING

Selection of the proper regulator size is an important element in achieving proper operation, minimal pressure droop, quiet operation, and minimum maintenance. The size should be based on the maximum load at the minimum inlet pressure at which the load occurs. If the demand varies widely, it may be advisable to install parallel runs, with the second run opening at a predetermined pressure drop to avoid the problem of a single large regulator's throttling near the closed position. A further advantage of installing parallel regulators is that the relief valve, if provided, is required to protect against the failure of only one regulator-whichever has the larger capacity. Excessive pressure droop under maximum conditions should be avoided.

NOISE CONTROL

Usually it will be prudent to include a noise analysis in the design work for the district regulator station. The regulator is usually the primary noise generator, but it is not the only one. High gas flow velocities, large pressure reductions, and abrupt changes in direction of flow - all creating turbulence generate noise. A control valve with a straight-through flow design, such as the "expandable sleeve" valve, is inherently less noisy than one with high turbulence. Regulator manufacturers provide design data on noise emissions for varying flow conditions.

Regulator valve cages, designed for noise control, are available. They dissipate acoustic energy by directing the gas through slots or small openings. Additional noise attenuation may be achieved by use of a silencer and/or a diffuser downstream of the regulator. Other methods of noise control include use of heavy wall pipes; sweep bends for directional changes; full open shutoff valves; buried piping; and sound absorbing material for wrapping exposed pipes. Enclosing a facility in a building designed for acoustical control is effective, but operating and maintenance personnel must be protected from excessive noise exposure while working within the building.

It is easier to control noise at the source by good design than it is to mask the noise after it is generated.

OVERPRESSURE PROTECTION

The modern gas regulator is a highly reliable device, but failures do occur due to physical damage, equipment failure, and the presence of foreign material in the gas stream.

Gas may contain moisture, dirt, sand and/or stones, welding slag, metal cuttings from tapping procedures, and other debris. Problems caused by such foreign material in the gas stream are most prevalent following construction on the line supplying gas to the district regulator station. Small pilot regulators and other restricting orifices should be protected from plugging by the installation of small gas filters upstream. Primary regulators are not as sensitive to small particles and may be protected from larger debris by the installation of strainers upstream from the regulators. Filters and strainers should be monitored closely, and a strict servicing schedule should be maintained.

Regulators with diaphragm actuators tend to fail in either the open or closed position on loss of loading pressure depending on whether the main spring is designed to open or close the valve. The designer of the district regulator station must make a choice based on the nature of the distribution system being supplied. A common practice is to use a fail-open primary regulator and a fail-closed monitor regulator. In the event of a single failure, two fail-closed regulators installed in parallel will provide continuity of service while reducing the probability of over pressurization. However, it should be remembered that when downstream-sensed pressure is lost, the regulator always would fail open whether the regulator design is "fail-open" or "fail-shut."

Protecting the distribution system from overpressure resulting from regulator failure may be accomplished by the use of several devices, the most common of which are relief valves, series regulators, and monitor regulators; occasionally automatic shutoff valves are used. These devices were discussed in Chapter 12. The above-grade regulator station shown in Figure 143 illustrates use of a relief valve for overpressure protection. They should not be used in urban areas unless gas can vent safely without the likelihood of entering nearby buildings. Though it is not shown in Figure 142, some provision for overpressure protection must be associated with the regulator in the vault station.

Figure 143 shows a typical underground station layout with monitor protection. Figure 144 shows a typical above ground layout with relief protection.

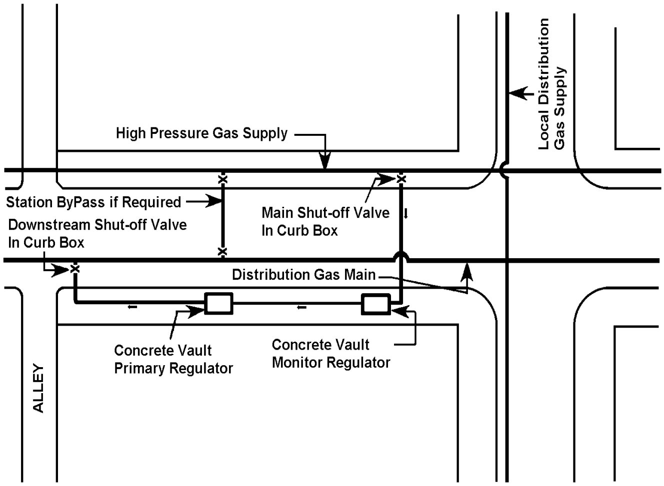

Figure 143. **Typical underground regulator station.**

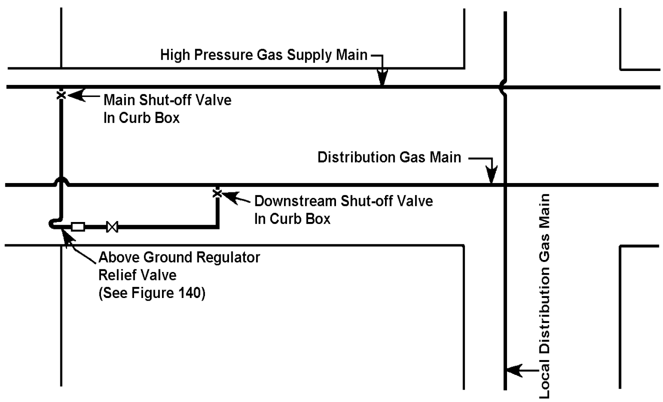

Figure 144. **Typical above ground regulator station.**

It should be noted that monitor protection may also be installed above ground in suitable locations, and relief protection may also be installed underground. However, the relief stack must be located so that the gas can be blown to the atmosphere without hazard. Many companies' standards are 6.5 ft to 7 ft (1.98 m to 2.13 m) above grade.

The conditions that will be created when an overpressure-protection device operates must be considered when the type of device is being selected. Table 77 presents the various scenarios that occur when various types of overpressure-protection devices are activated.

It is important that the failure of a regulator be signalled immediately to operating personnel. Telemetered pressure data taken near the regulator outlet will provide this information effectively. Recording charts at the district regulator station do not reveal their data until a scheduled chart change is made. Blowing relief valves in a populated area are usually reported by the public.

PIPING AND VALVES

Although regulator installations in vaults or buildings often are standardized within distribution companies, the piping to and from the installation is controlled by local conditions and varies accordingly. Figures 144 and 145 are examples of piping configurations to and from district regulator stations. Low pressure systems typically are older and usually are found in urban areas. Piping and equipment are large, and district regulator stations require considerable space. Higher-pressure systems are usually newer and located in newer areas. Piping and equipment usually are smaller for equivalent flows, and regulator stations may be more compact and require less space. District regulator stations should have a station inlet valve and a station outlet valve; the latter can prevent back feeding in case emergency shutoff is required and is helpful for maintenance purposes.

Both valves should be separated from the regulator by a distance sufficient to permit isolating the station in case of an emergency such as a fire. Separation distances vary from 25 ft to 50 ft (7.6 m to 15 m) but can be greater. If the distribution system requires a feed at the district regulator station, a station bypass should be installed unless a pair of regulators in parallel is used. The bypass valve by code requirements is locked in a closed position to prevent accidental opening. If installed underground with a curb-box access, it should be identified in such a manner that improper opening, resulting in downstream overpressure, will not occur. If the bypass is used as a temporary manned feed, a means to monitor downstream pressure is required. The operator should consider the use of written procedures to ensure bypass and other station valves are operated correctly.

TABLE 77
Comparison of Overpressure-Protection Devices

Condition with Device Activated	Relief	Working Monitor	Monitor	Series Regulation	Shut Off	Relief Monitor
Customer remains on	Yes	Yes	Yes	Yes	No	Yes
Gas vented to atmosphere	Yes	No	No	No	No	Minor
Manual resetting required	No	No	No	No	Yes	No
Regulator capacity reduced	No	Yes	Yes	Yes	No	No
Immediate action by gas company required?	Yes	No	No	No	Yes	Maybe
Condition during Normal Operation						
Activated	No	Yes	No	Yes	No	No

The selection of shutoff valves is important in the design of the district regulator station. Valves must be accessible and operable under emergency conditions. Valve types available are plug valves (lubricated and non-lubricated), gate valves (rising and non-rising stem), and ball valves. Plug valves usually have restricted ports, which may be a factor at high flow rates in lower pressure applications. The lubricated plug may require lubrication before it can be operated and/or shut off tightly.

Over lubrication, which admits grease into the gas stream, should be avoided. Plug valves provide good throttling capabilities due to their internal design and are recommended for bypass and blow off applications. Gate valves usually have full-open bore. When installed underground, they should have a non-rising stem to avoid exposing threads to dirt and moisture in the open position. Gate valves normally operate easily without maintenance, although some have been susceptible to stem leaks through the packing gland and to the collection of foreign material in the bottom seating area. Ball valves are available with either full-opening or restricted ports; they are easy to operate and provide good shutoff if proper seat materials are used. Due to lack of lubrication requirements and small pressure drops, the ball or gate valves are best located between regulators and meters.

When vaults are used, the designer of the district regulator station should consider the effect of a single incident-such as an explosion-that could result in system overpressure due to the failure of both the regulator and the overpressure device. To prevent such an occurrence, there should be adequate separation between the regulator and the protection device.

Piping and control lines shall be located so as to minimize accidental damage. Piping and control lines in pits and vaults should be protected against atmospheric corrosion; tubing should be stainless steel.

INLET, OUTLET, BYPASS, AND CONTROL PIPING DESIGN

Proper pipe size selection, piping and fitting configuration, and control-line location are important to obtaining optimum performance from a district regulator installation. Inlet and outlet piping should be sized for maximum flow conditions, with velocity considered for noise control. Anticipated future load also should be considered. Selection of gradually tapered expanders and long-radius bends helps reduce turbulence, noise, vibration, and pressure loss.

Bypass piping should be sized in accordance with the required station capacity, and the manual throttle valve should be within sight of a connection for an outlet pressure gage.

Pressure-sensing control piping taps should be located downstream in the larger sized outlet piping. The pressure-sensing tap location must be located at a sufficient distance downstream from valves, tees, ells, or other fittings to minimize turbulence in the gas stream; eight to ten pipe diameters is recommended as a minimum. McGuire gives examples of several different regulator station designs.[3]

EXAMPLE

The following is a simplified exercise in sizing components for a district regulator station:

Load requirement	100 Mft^3/h (2.83×10^3 m^3/h)
MAOP of supply line	60 psig (414 kPa)
Minimum pressure in the supply line	30 psig (207 kPa)
MAOP of distribution system	10 psig (69 kPa)

Use the above ground regulator and relief valve configuration shown in Figure 142 and the regulator station layout shown in Figure 144 and the following assumptions:

3 in. (76 mm)	inlet piping
4 in. (101 mm)	outlet piping
2 in. (51 mm)	regulator
3 in. (76 mm)	relief valve
2 in. (51 mm)	by pass

Pipe and fittings from the supply line to the regulator include the following in equivalent length of 3 in. (76 mm) pipe:

1	3 in. (76 mm) gate valve	2 ft (0.6 m)
3	3 in. (76 mm) 90° long-radius weld ells	12 ft (3.7 m)
1	3 in. × 2 in. (76 mm × 51 mm) weld tee (run)	5 ft (1.5 m)
1	3 in. (76 mm) plug valve	12 ft (3.7 m)
1	3 in. × 2 in. (76 mm × 51 mm) weld reducer	5 ft (1.5 m)
	3 in. (76 mm) pipe	65 ft (19.8 m)
	Total 3 in. (76 mm) pipe equivalent	101 ft (30.8 m)

The capacity of the regulator can be obtained from manufacturers in the form of formulas, tables, nomographs, or PC software.

Calculation of the pressure drop for 100 Mft^3/h (2.83×10^3 m^3/h) flow with 30 psig (207 kPa) inlet and 101 ft (30.8 m) of 3 in. (76 mm) pipe gives 4.4 psi (30 kPa) using the Weymouth equation. Minimum pressure at the regulator now is 30 - 4.4 = 25.6 psig (177 kPa). The 2 in. (51 mm) regulator with 1¾ in. (45 mm) double-ported body is rated at 104 Mft^3/h (2.95×10^3 m^3/h) at 25 psig (172 kPa) inlet. Thus, the regulator is adequate.

A similar pressure drop determination for the 2 in. (51 mm) bypass will show that it also is adequate.

The relief valve must be sized for regulator failure under maximum pressure conditions. The allowable pressure increase, as per 192.201, for this 10 psig (69 kPa) system is 5 psi (34.5 kPa) (MAOP plus 50%). At a 12 psig (83 kPa) relief setting, the relief valve will relieve 130

Mft^3/h (3.68×10^3 m^3/h) with less than a 3 psi (21 kPa) increase over set point. At an inlet pressure of 60 psig (414 kPa), the failed regulator will pass about 700 Mft^3/h (1.98×10^4 m^3/h). The 3 in. (76 mm) relief valve is not adequate.

A 4 in. (102 mm) relief valve at the same relief setting will relieve 235 Mft^3/h (6.65×10^3 m^3/h) - the 4 in (102 mm) relief valve is adequate. We should install a 2 in. x 4 in. (51 mm × 102 mm) weld expander at the regulator outlet and a 4 in. (102 mm) full-open gate valve (locked open) ahead of the 4 in. (102 mm) relief valve. The relief valve should be installed downstream of the bypass and downstream of the regulator sensor line tap.

The outlet piping includes the following in equivalent length of 4-in. pipe:

1	2 in. × 4 in. (51 mm × 102 mm) weld expander	8 ft (2.4 m)
1	4 in. (102 mm) weld tee (branch)	6 ft (1.8 m)
1	4 in. × 2 in. (102 mm × 51mm) weld tee (run)	7 ft (2.1 m)
2	4 in. (102 mm) weld ells	10 ft (3.0 m)
1	4 in. (102 mm) gate valve	2 ft (0.6 m)
	4 in. (102 mm) pipe	20 ft (6.1 m)
	Total 4 in. (102 mm) pipe equivalent	63 ft (19 m)

The pressure drop for 100 Mft^3/h (2.83×10^3 m^3/h) flow with 10 psig (69 kPa) inlet and 100 ft (30.5 m) of 4 in. (102 mm) pipe is 1.1 psi (7.6 kPa). This leaves 8.9 psig (61 kPa) delivery pressure into the distribution main at maximum flow. In this example, it would be advisable to run the regulator's downstream control line directly to the distribution main to eliminate the effect of the pressure drop through the outlet piping.

Although the 4 in. (102 mm) piping immediately downstream of the regulator is adequate in terms of velocity up to 4 in. (102 mm) gate valve downstream of the regulator, the piping downstream of the 4 in. (102 mm) gate valve needs to be increased to a larger size in order to reduce the velocity and the associated pressure drop to the distribution main. This outlet header piping should be at least as large as the distribution main to which the station is being connected. At the A.G.A System Capacity Design Best Practices Roundtable held in September 1997, the general consensus was that the velocity in outlet header piping should be less than 65 ft/s (20 m/s). Solving the velocity equation given for pipe size results in a required internal diameter of 6.835 in. (173.6 mm). This would require an 8 in. (204 mm) pipe (either plastic with an underground transition or steel) to achieve a velocity lower than 65 ft/s (20 m/s).

$$\mathrm{ID\ (in.)} = \sqrt{\frac{750 \times Q\,(\mathrm{Mft^3/h})}{P\,(\mathrm{psia}) \times V\,(\mathrm{ft/s})}}$$

$$\text{ID} = \sqrt{\frac{750 \times 100}{24.7 \times 65}} = 6.835 \text{ in. } (173 \text{ mm})$$

Section 9.5 of A.G.A. Gas Measurement Manual Part No. 9, 1988 is another good reference for valves and piping configurations.